INTERMOUNTAIN POWER SERVICE CORPORATION

September 24, 2003

Mr. Richard Sprott, Director
Division of Air Quality
Utah Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Attention: Milka Radulovic, New Source Review Section

Dear Director Sprott,

NOTICE OF INTENT: Additional Information Submittal

On September 23, 2002, Intermountain Power Service Corporation (IPSC) submitted a notice of intent (NOI) to make certain changes at the Intermountain Generating Station (IGS) near Delta, Utah. As part of the permitting process, IPSC installed and tested an over fire air system for NOx control under the authority of an experimental Approval Order (AO) DAQE-AN0327012A-03 issued by the Division of Air Quality (DAQ). The Intermountain Power Service Corporation (IPSC) is hereby submitting the results and analyses of the testing so that final approval and permitting may proceed.

BACKGROUND

IPSC's NOI requested, among other things, approval to install over fire air (OFA) to control nitrogen oxides (NOx) emissions. IPSC had found that due to changing fuel quality, it appeared likely that additional NOx control such as OFA would be helpful in meeting permit conditions for continued long term operation. Since OFA operation may cause carbon monoxide emissions to increase by a net significant amount when NOx emissions are minimized, IPSC ultimately sought approval to install OFA under Prevention of Significant Deterioration (PSD) requirements. PSD specifies the criteria under which OFA may be installed and operated with no adverse impact to air quality.

As part of making a PSD determination, it was necessary to perform a demonstration project on OFA operation. On February 5, 2003, IPSC submitted a Notice of Intent requesting approval to install and test an over fire air (OFA) system on Unit 1 under an experimental permit. Testing results are intended to be used to establish permitting parameters for installing another OFA system on Unit 2 and to demonstrate PSD compliance with the full time operation of both systems.

OFA DEMONSTRATION PROJECT TEST SUMMARY

The OFA was installed and tested to ascertain the operating characteristics and environmental aspects of good combustion practice that minimizes carbon monoxide (CO) emissions while simultaneously controlling NOx emissions. It was expected that the use of OFA could increase CO emissions by a net significant amount (100 tons per year) as NOx emissions are minimized. The results of the testing will help DAQ and the IPSC to determine permit conditions that represent the Best Available Control Technology (BACT) for CO when the OFA is utilized.

OFA was installed in the Unit 1 boiler during its Spring outage. Initial operation of the OFA system upon restart of Unit 1 presented several challenges in integrating OFA operation with existing combustion systems. It took significant time and effort to troubleshoot and pinpoint the causes, which included both mechanical breakdown and uneven fuel and air flows.

Once the causes were identified and corrected, tuning began for the OFA system to operate satisfactorily pursuant to its design. Once the OFA system performance was optimized, IPSC performed environmental testing to identify specific emission characteristics in various states of operation. That testing occurred September 6 - 9, 2003, and all testing data, along with pre-construct test data, are included with this report. Pre-construct testing occurred prior to the Spring outage when OFA was installed in order to obtain baseline information.

Prior NOI submittals applicable to OFA indicated one operating condition for OFA was full port, where both 1/3 and 2/3 dampers were open. We have since determined that operating OFA in such a manner does not provide for optimal combustion due to lower port velocities. IPSC predicts that 2/3 open damper is the most likely long term operating condition for the over fire air system.

A full test report is included with this letter, along with copies of the air quality impact modeling, the experimental approval order, the test report required by that AO, and a compliance assurance monitoring (CAM) plan applicable to CO.

OFA DEMONSTRATION PROJECT TEST RESULT OVERVIEW and ANALYSIS

The results of the testing are included with this letter. In analyzing the data, IPSC finds that the single best parameter that correlates most with CO emissions is percent O_2 in the boiler exit flue gas. As shown by the attached charts, CO concentration can be determined by percent O_2 based upon specific operating conditions of the over fire air system.

A relationship formula has been derived for each curve based upon best fit analysis of test data. OFA operating condition can be distinctly identified based on damper status. Thus, the tables represent No OFA, 1/3 open OFA, 2/3 throttled OFA, and 2/3 open OFA operation. CO concentration curves are represented for each table and are related to percent O_2 generally as:

$$[C_{ppm}] = n * (O_2\%)^a,$$

where; $[C_{ppm}]$ = concentration of CO in parts per million;
n = curve specific factor;
$O_2\%$ = percent O_2 measured at boiler exit;
a = curve specific exponent.

The curves provide a clear demarcation of the boundaries of what IPSC believes to be Good Combustion Practice (GCP). Basically, GCP falls in the areas bounded by the O_2 concentration that relates to 250 ppm CO, and the station emission limit for nitrogen oxides (NOx). Based upon historical operating conditions since the installation of overfire air, we believe these boundaries are properly scaled to include most OFA settings for various coal qualities, yet still result in low average CO emissions over a 30 day rolling period. CO concentration of 250 ppm was selected as an upper limit to GCP because it provides a break point prior to exponential increases in CO at low O_2 levels. The lower boundary for CO would normally be 0 ppm, but will in practice be somewhat higher due to NOx limits.

The 250 ppm concentration point for CO relates to 2% O_2 for each OFA operating condition except 2/3 open damper. In 2/3 open condition, 250 ppm CO corresponds to 1.75% O_2, as measured at the boiler exit flue path.

Variability in boiler operation can result in certain short term excursions of CO concentrations. Specifically, mill swaps, load change, and other combustion specific parameters can cause average CO emission concentrations of up to 800 ppm for one hour duration, and 400 ppm concentrations of up to 8 hour duration. IPSC has modeled for air quality impact at these short term concentrations, and find that they are well below any significance level for CO.

CO BACT & RECOMMENDED PERMIT CONDITIONS

IPSC recommends that for permitting OFA for installation in Unit 2, and continued operation for both Units 1 and 2, a limit equivalent to 0.143 lb/mmbtu in pounds per hour based upon a 30 day rolling average would be protective of the environment and meet best available control technology (BACT). At design heat input, 0.143 lb/mmbtu represent 180 ppm CO concentration. When converted, this equals 1320 lb/hr at 2.25% O_2. When related back to percent O_2 levels in the boiler, historical operation indicates that this is the average result when OFA is operated in the GCP range shown on the test result curves. Coal combustion naturally incurs fluctuations in emissions due to varying coal quality and boiler operating conditions. We believe that GCP contains those fluctuations, and therefore recommend that a single permit limit of 1320 lb/hr based upon a 30-day rolling average (except for start-up, shut down, planned / maintenance outage, or malfunction) represents BACT for this type of retro-fit control device.

Although our initial NOI provided an expectation that CO emissions would be level at vendor guarantees, we predict that operation will more likely slide to the rates encompassed by the curves described above. The vendor guarantee was for a specific condition at a single value, which is unlikely to be maintained in the normal flux of firing boilers of this size.

Recent permit actions and corresponding conditions for CO have been provided to your office (attached). This review indicates clearly that the recommended permit limit is within the realm of accepted conditions.

Further, since CO emissions during upset conditions, such as mill swap, have been modeled well below significant impact levels under PSD, shorter term limits are unnecessary. Operation of the boiler must always be maintained to achieve the lower 30 day limit, so upset conditions will be corrected quickly, limiting any chance of a NAAQS violation.

Since testing has provided a solid foundation for correlating CO concentration to percent O_2, IPSC believes that direct continuous CO emission monitoring is unnecessary. IPSC recommends utilizing the formulas derived from the test data to determine CO based upon the OFA operating conditions at any given time. Percent O_2 data can be collected on a continuous basis (four times per hour), and thus would be equivalent to CEM for CO. We have provided a CAM plan that incorporates this methodology.

Finally, good combustion practice is the only technology currently available for this type and size of boiler. Potential control technologies for CO were identified from a number of sources including the EPA RBLC database, control technology vendors, technical journals and web sites, and other recently issued permits. A BACT analysis was performed in that standard top down convention. The only other type of technology, catalytic oxidation, is as yet unfeasible and undemonstrated for this type of boiler. Based on the above analysis, a Good Combustion Practice (GCP) for CO is selected as BACT. IPSC has previously provided a detailed discussion on what GCP entails for boiler operation utilizing OFA, and has defined that those parameters reflect GCP based upon percent O_2.

POTENTIAL TO EMIT

The current PTE for CO at IGS is 1989.6 tons /yr. Based upon the new proposed limit, the PTE for CO will change to 11692.3 tons /yr (11,561.3 tons from the main boilers, 131 tons from auxiliary equipment). This relates to a 9, 700 ton increase in CO if NOx were minimized to a constant design emission rate of 0.37 lb/mmbtu, which when annualized, is 7,900 tons lower than the NOx PTE.

Since IPSC is accepting a 30-day 1320 lb/hr emission limit for CO, we believe that a tons/yr permit condition is no longer necessary because this value is subsumed within the short term limit.

REVIEW OF OTHER NOI PROPOSALS

The September 23, 2002 NOI requested DAQ review for several other proposed items. Specifically, IPSC has determined rectified power drives and motors for induced draft fan motors need to be replaced due to obsolescence. Also, IPSC has approval to increase surface area to the main boilers, and we have clarified the location. IPSC is performing replacement-in-kind of Units 1 & 2 Low-NO_X burners. These changes are needed specifically for reliability, performance and/or routine maintenance needs, and will not increase plant capacity or PTE. IPSC is still requesting a review and determination from DAQ for those projects. IPSC believes that based upon our assertions, as well as verified by WEPCO compliance requirements already in place, these proposed changes should not be significant to permitting in any way.

NEW PROPOSED NOTICE OF INTENT

As previously discussed with your office, we are hereby including for DAQ review one additional proposed change to the Intermountain facility. IPSC is proposing to extend venting from reaction tanks inside of the wet limestone flue gas desulfurization building to and through the building roof. Such an alteration will change current low level fugitive emissions from those tanks to point source emissions, and IPSC is filing this NOI accordingly.

Each scrubber module has a reaction tank that cycles slurry containing sulfur components scrubbed from flue gas. Conversion from sulfites to sulfates occurs within the tank. The tank level is maintained in such a manner that flue gas cannot penetrate through the slurry surface and escape the tank. Limestone is utilized for the scrubbing process, and accordingly CO_2 is off-gassed as a byproduct. Slurry is blown down and mixed with fly ash for ultimate disposal. The tanks currently vent to inside of the scrubber buildings.

The moisture and heat from the venting has been problematic inasmuch as corrosion is accelerated on building components where these tanks vent. We are proposing to extend venting through the roof of each building for each tank.

There are six tanks in each of the two scrubber buildings. Four are in operation at any given time for each unit to control sulfur and acid gas emissions. We have included a diagram indicating proposed venting, and a worksheet indicating worst case emissions. We do not believe that particulates are a significant part of venting, but we have included those calculations based upon evaporation rates. Emissions are characterized worst case as follows:

Estimated Vent Flow Rate	2500cfm
Emission Temperature	51° C
Vent Particulate Emission Rate	0.11 tons/yr
Number of Operating Vents	8 (out of 12)
Total Emission Rate (PM10)	0.88 tons/yr
Stack Vent Elevation	4825 ft (149 ft above ground level)

If you require any further information concerning the testing of OFA or issues tied to this notice of intent, please contact Mr. Dennis Killian, Superintendent of Technical Services at IPSC, at 435-864-4414, or dennis-k@ipsc.com .

Inasmuch as this letter will affect our Title V operating permit #2700010002, I hereby certify that, based upon the information and belief formed after reasonable inquiry, the statements and information in this and associated documents are true, accurate, and complete.

Cordially,

George W. Cross

George W. Cross
President and Chief Operations Officer

BP/RJC/co

Enclosures: CH2MHill Air Quality Modeling Report
CAM Plan for CO
Page 3 of CH2MHill Technical Memorandum
Proposed Vent Diagrams & Calculation Worksheet
Experimental AO Test Report
Engineering OFA Test Report
Data Files Diskette

cc: Blaine Ipson
Jerry Hintze
Eric Tharp, LADWP

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CH2MHILL

September 23, 2003

176784.A0.02

Rand Crafts
Intermountain Power Service Corporation
850 West Brush Wellman Road
Delta, Utah 84624

Subject: IPP Over-Fire Air Project: Carbon Monoxide Impacts

Dear Rand:

This letter presents a summary of our analysis of potential carbon monoxide (CO) impacts from the proposed addition of over-fire air to the existing Units 1 and 2 (OFA Project) at the Intermountain Power Project (IPP). CH2M HILL evaluated the impact from the CO emissions resulting from the OFA Project on the following:

- Class II area National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments
- Class I area PSD increments and air quality related values (AQRVs)

The IPP is situated in an area that is designated as attainment for all criteria pollutants, while the surrounding areas are designated as Class II areas for PSD permitting.

Intermountain Power Service Corporation (IPSC) requested that CH2M HILL conduct the analysis described here. The scope of the project was summarized in our proposal to IPSC dated November 12, 2002. This report provides an overview of the analysis, including dispersion modeling inputs and results.

Selected Model

To evaluate air quality impacts in the Class II areas surrounding the IPP, CH2M HILL used the EPA Industrial Source Complex Short-Term (ISCST3) dispersion model. The ISCST3 model (Version 02305) is the latest generation of the EPA model that is recommended for predicting impacts from industrial point sources. The model combines simple terrain and complex terrain algorithms, which make it ideal for the terrain surrounding the IPP. The selected model is the same model that was proposed for use with the Intermountain Power Project (IPP) Unit 3 Project and approved for use by the Utah Division of Air Quality (UDAQ).

The ISCST3 model was run with EPA regulatory default options, with the addition of the model option for processing missing meteorological data. By using the missing data processing routine, the model can recognize the periods of missing data and adjust calculated impacts in the same manner that calm winds are processed.

Meteorological Input

For meteorological input to the ISCST3 model, CH2M HILL used data collected from the 50-meter (m) level from the meteorological monitoring station at the IPP. Data from the IPP station meet all EPA requirements for consideration as representative of the IPP. The period of record represented by the data is the most current, as the continuous collection of meteorological data began at the IPP station on July 19, 2001. A full calendar year of data was used for the modeling, spanning from August 1, 2001 to July 31, 2002. Twice-daily mixing heights to couple with the on-site surface data were obtained through the use of raw upper-air data from the Salt Lake City National Weather Service station, and the EPA Mixing Heights Program. Figure 1 presents a wind rose for the 50-m data.

Receptor Grid

The base receptor grid for ISCST3 modeling consisted of receptors that were placed at the ambient air boundary, and Cartesian-grid receptors that were placed beyond the boundary at spacing that increased with distance from the origin. Ambient boundary receptors were placed at 50-m intervals. Beyond the ambient boundary, receptor spacing was as follows:

- 100-m spacing from property boundary to 1 kilometer (km) from the origin
- 250-m spacing from beyond 1 km to 3 km from the origin
- 500-m spacing from beyond 3 km to 20 km from the origin
- 1,000-m spacing from beyond 20 km to 50 km from the origin

Terrain in the vicinity of the IPP was accounted for by assigning elevations to each modeling receptor. CH2M HILL used Digital Elevation Model (DEM) data from the U.S. Geological Survey (USGS) to determine receptor elevations. We obtained DEM data from the USGS National Elevation Dataset (NED). The NED has been developed by merging the highest-resolution, best-quality elevation data available across the United States, and is the result of the USGS effort to provide 1:24,000-scale (7.5-minute) DEM data for the entire continental United States. Figure 2 presents a depiction of terrain features near the IPP.

Building Downwash

Building downwash effects for structures near Units 1 and 2 were determined with the EPA Building Profile Input Program (BPIP, version 95086).

Emissions and Exhaust Parameters

Rather than attempt to estimate and evaluate the CO emissions increase from the OFA Project alone, the maximum 1-hour and 8-hour emissions from full operation of each unit (at various loads, after approved uprate modifications) were input to the ISCST3 model. This represents a conservative approach to estimating the impacts from the OFA Project. Attachment 1 presents the modeled emissions and exhaust parameters for each load condition.

Maximum 1-hour CO emissions for the modeling analysis were based on an emission rate of 0.62 lb/MMBtu. This emission rate is based on data collected during the 2003 OFA performance testing for IPP Unit 1. To arrive at a conservative estimate of worst-case 1-hour emissions at approved full uprate load operation, the value of 0.62 lb/MMBtu was multiplied by the maximum heat input for full load (9,225 MMBtu/hr). To arrive at emissions for reduced loads (75% load and 50% load), the 0.62 lb/MMBtu value was multiplied by the heat inputs expected at the particular reduced load. Exit velocities for reduced load conditions were calculated by scaling the flow at 100% load to reflect the expected flow at 75% and 50% loads.

To estimate maximum 8-hour emissions, an emission rate of 0.31 lb/MMBtu was multiplied by the expected heat input for each unit at 100%, 75%, and 50% loads. This emission rate is based on operating data accounting for unit load changes, boiler fluctuations and pulverizers being taken out of service over an eight-hour period. Based on operational data, the annual average CO emissions are approximately 0.143 lb/MMBtu.

Because the Unit 1 and Unit 2 flues are released from a common shell (stack) location, both units were modeled with a common pair of Universal Transverse Mercator (UTM) coordinates, representing the center of the common stack. Similarly, because the maximum estimated emissions are identical for each unit, the two sources were modeled as a single point source, with the emissions for a single unit doubled to represent both units within the model.

Results

CH2M HILL compared the highest 1-hour and 8-hour impacts predicted by the ISCST3 model for 100%, 75%, and 50% loads to the Class II Area modeling significance levels. The highest predicted 1-hour impact was 941.5 $\mu g/m^3$. This impact was estimated to occur with 100% load, approximately 35 km west-northwest of the Units 1 and 2 stack, and in an area with receptor spacing of 1,000 m. According to modeling guidelines published by the UDAQ: "In general, the receptor network will be considered adequate if the difference in concentrations at neighboring receptors is no larger than one half the difference between the maximum modeled concentration and the NAAQS or increment under consideration" (UDAQ, 2000). In this case, the air quality standard under consideration is the Class II modeling significance level, and one half of the difference between the maximum modeled concentration (941.5 $\mu g/m^3$) and the modeling significance level (2,000 $\mu g/m^3$) is approximately 529 $\mu g/m^3$. The difference between concentrations at neighboring receptors is more than 529 $\mu g/m^3$, and therefore an additional model run with a fine-spaced receptor grid was conducted for 1-hour CO impacts. We constructed a receptor grid with 100-m spacing around the maximum coarse grid receptor and repeated the 1-hour CO analysis. The highest predicted 1-hour impact with the fine-spaced grid was 984.6 $\mu g/m^3$.

The maximum 8-hour impact of 119.8 $\mu g/m^3$ also occurred with 100% load operation. This impact occurred approximately 2.5 km south of the Units 1 and 2 stack in an area with 250-m receptor spacing. The difference between concentrations at neighboring receptors is much less than one half of the difference between the maximum modeled concentration and the modeling significance level (500 $\mu g/m^3$), and therefore the receptor network was adequate to capture the maximum 8-hour impacts of CO.

The maximum predicted 1-hour concentration of CO is less than 50% of the modeling significance level, while the maximum 8-hour concentration is less than 24% of the modeling significance level. These modeled impacts were conservatively predicted for full operation of both units after completion of the OFA Project as opposed to simply evaluating the increase in CO emissions that would be expected from the project. Therefore the analysis demonstrates that air quality impacts of CO from Units 1 and 2 after completion of the OFA Project will be insignificant, and Class II NAAQS and PSD increments will not be threatened.

TABLE 1
Maximum Estimated Carbon Monoxide Impacts

Averaging Period/Load	Maximum Estimated Impact ($\mu g/m^3$)	UTM Location	Class II Area Modeling Significance Level ($\mu g/m^3$)
1-hour/100% Load	984.6	331,054 m East 4,382,064 m North	2,000
1-hour/75% Load	848.3	366,054 m East 4,401,464 m North	2,000
1-hour/50% Load	733.3	366,054 m East 4,401,464 m North	2,000
8-hour/100% Load	119.8	364,804 m East 4,371,964 m North	500
8-hour/75% Load	103.8	364,804 m East 4,371,964 m North	500
8-hour/50% Load	81.9	365,054 m East 4,376,464 m North	500

Notes:
$\mu g/m^3$ = micrograms per cubic meter
UTM = universal transverse mercator
m = meters

Air Quality and AQRVs in Class I Areas

The IPP plant is located within 150 km of Capitol Reef National Park (NP) in Utah, the nearest Class I area to the IPP. The plant is located within 250 km of several other Class I areas in Utah, including Zion NP, Bryce Canyon NP, and Canyonlands NP. Because of the presence of these Class I areas, CH2M HILL evaluated the potential impacts of CO emissions from the Units 1 and 2 OFA Project on Class I area air quality and AQRVs.

No Class I area PSD increments have been established for CO. Therefore, the OFA Project will not cause or contribute to a violation of a Class I area PSD increment.

To evaluate the effect of CO emissions from the OFA Project on Class I area AQRVs, CH2M HILL examined the document titled *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report* (FLAG, 2000) to determine the Class I AQRVs that are of most concern to the Federal Land Managers (FLM). The goal of the FLAG process has been to provide consistent policies and processes both for identifying AQRVs and for evaluating the effects of air pollution on AQRVs, primarily those in Federal Class I air quality areas.

Details are provided in the FLAG document for the types of analyses that should be conducted for AQRVs. These analyses include: visibility impacts, acid deposition of sulfur and nitrogen compounds, and ozone effects on vegetation. Carbon monoxide is an air pollutant that does not contribute to visibility degradation, acid deposition, or ozone formation. Therefore, CO emissions from the OFA Project will not adversely affect any Class I area AQRVs.

List of Files

The ISCST3 modeling files have been wriiten to CD and are enclosed with this report. The file names and descriptions are as follows:

IPP_CO_1.DTA(.LST) – ISCST3 input (.DTA) and output (.LST) files for maximum 1-hour CO impacts

IPP_CO_1F.DTA(.LST) – ISCST3 input (.DTA) and output (.LST) files for maximum 1-hour CO impacts (fine grid)

IPP_CO_8.DTA(.LST) – ISCST3 input (.DTA) and output (.LST) files for maximum 8-hour CO impacts

IPP50M.MET – Meteorological input file

References

UDAQ, 2000. *Utah Division of Air Quality Modeling Guidelines (Revised Draft)*, Utah Division of Air Quality, Technical Analysis Section, August 17, 2000.

FLAG, 2000. *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report*, December 2000.

Please contact Josh Nall at (720) 286-5362 if you have any questions.

Sincerely,

CH2M HILL

Robert L. Pearson, Ph.D.
Vice President

Attachment

Figure 1 – Wind Rose

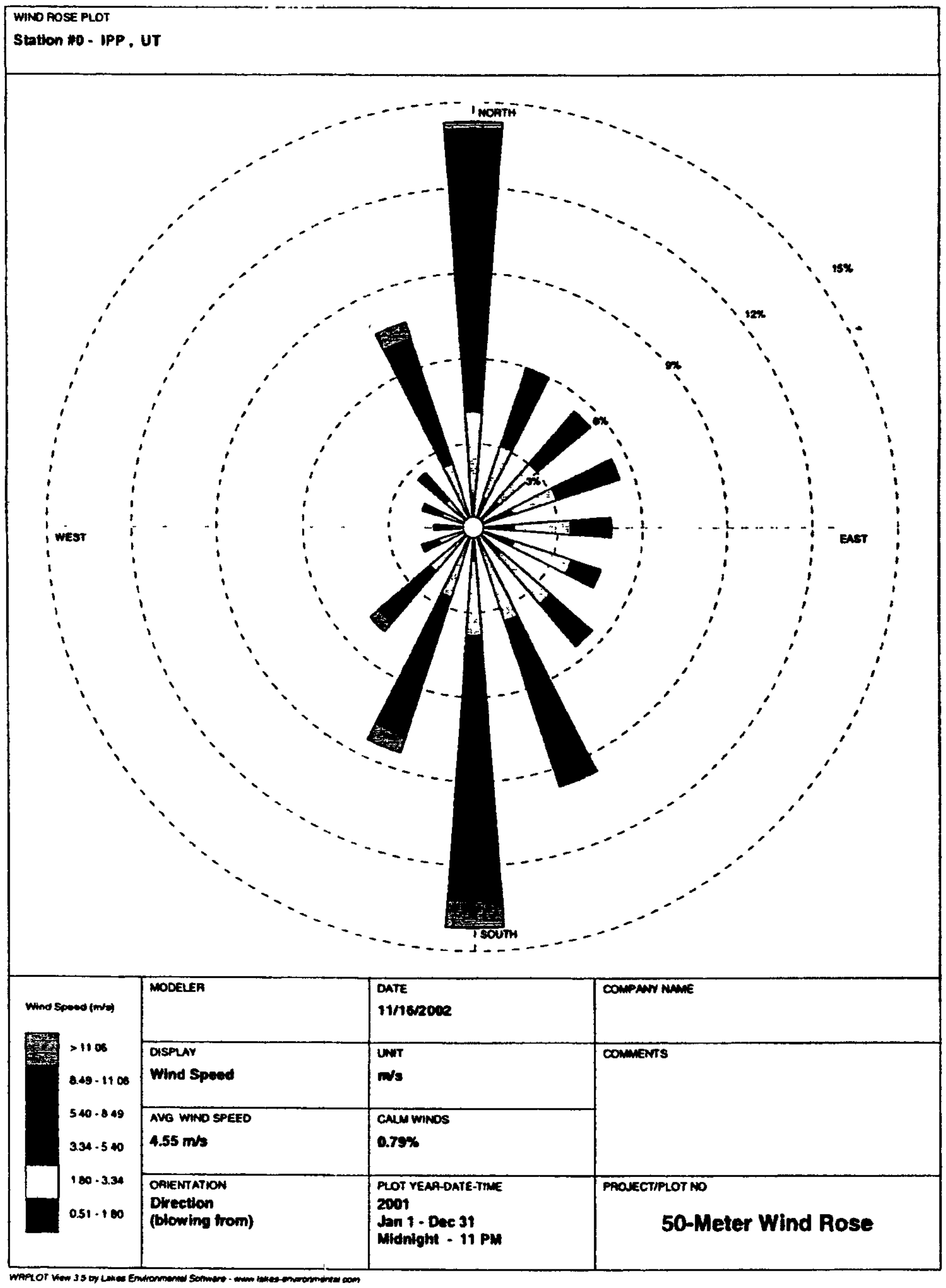
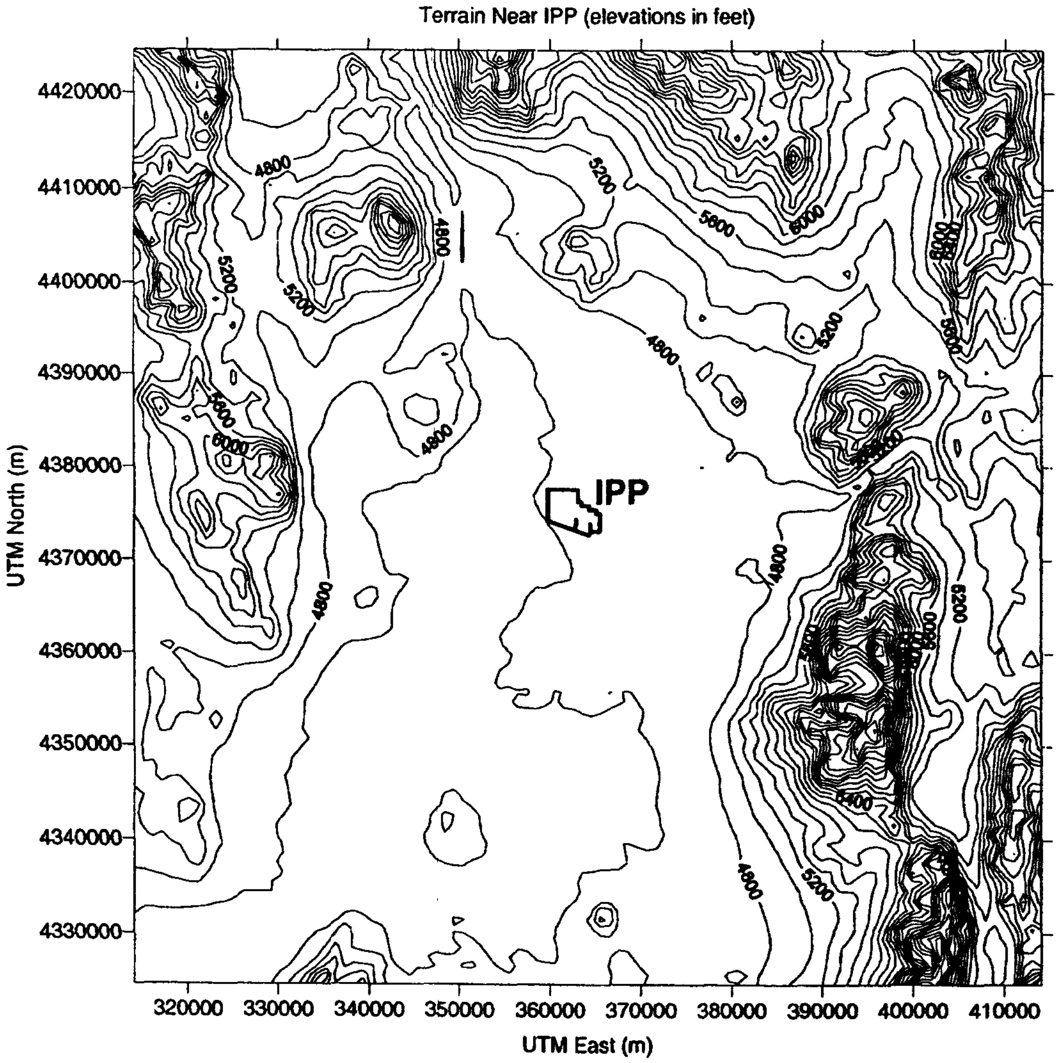


Figure 2 – Terrain Features



ATTACHMENT 1

IPSC Carbon Monoxide (CO) Modeling for OFA Project

Modeling Input Summary - Unit 1

Modeling Scenario	Heat Input	Stack Height	Stack Diameter	Stack Flowrate	Exit Velocity	Exhaust Temperature	Maximum 1-Hour CO Emissions	Maximum 8-Hour CO Emissions	Annual Average CO Emissions
	MMBtu/hr	ft	ft	acfm	ft/sec	°F	lb/hr	lb/hr	lb/hr
Full Load Operation - 100%	9,225	712	28.0	3,056,345	82.7	115	5,719.50	2859.75	1319.18
Partial Load Operation - 75%	6,919	712	28.0	2,292,259	62.0	115	4,289.63	2144.81	989.38
Partial Load Operation - 50%	4,613	712	28.0	1,528,173	41.4	115	2,859.75	1429.88	659.59

Modeling Input Summary - Unit 2

Modeling Scenario	Heat Input	Stack Height	Stack Diameter	Stack Flowrate	Exit Velocity	Exhaust Temperature	Maximum 1-Hour CO Emissions	Maximum 8-Hour CO Emissions	Annual Average CO Emissions
	MMBtu/hr	ft	ft	acfm	ft/sec	°F	lb/hr	lb/hr	lb/hr
Full Load Operation - 100%	9,225	712	28.0	3,056,345	82.7	115	5,719.50	2859.75	1319.18
Partial Load Operation - 75%	6,919	712	28.0	2,292,259	62.0	115	4,289.63	2144.81	989.38
Partial Load Operation - 50%	4,613	712	28.0	1,528,173	41.4	115	2,859.75	1429.88	659.59

Modeling Input Summary - Unit 1+2 (metric)

Modeling Scenario		Stack Height	Stack Diameter		Exit Velocity	Exhaust Temperature	Maximum 1-Hour CO Emissions	Maximum 8-Hour CO Emissions	Annual Average CO Emissions
		m	m		m/sec	K	g/s	g/s	g/s
Full Load Operation - 100%		217.0	8.53		25.21	319	1,441.31	720.66	332.43
Partial Load Operation - 75%		217.0	8.53		18.91	319	1,080.99	540.49	249.32
Partial Load Operation - 50%		217.0	8.53		12.61	319	720.66	360.33	166.22

Notes:

1) The maximum 1-hour CO emissions are based on an emission rate of 0.62 lb/MMBtu. This emission rate is based on data collected during the 2003 Overfire Air (OFA) Performance Testing for IPP Unit 1.

2) The maximum 8-hour CO emissions are based on an emission rate of 0.31 lb/MMBtu. This emission rate is based on operating data accounting for unit load changes, boiler fluctuations and pulverizers being taken out of service over an eight hour period.

3) The annual average lb/hr CO emissions are based on an average emission rate of 0.143 lb/MMBtu.

4) lb/hr CO = lb/MMBtu CO x MMBtu/hr Heat Input.

5) Stack flow and stack exit velocity were estimated for 75% and 50% load conditions.

IP10_003308

Title V CAM Equivalent Monitoring
Intermountain Generating Station
Main Boiler Carbon Monoxide Emissions

I. Background

A. Emissions Unit

Description:	Steam Generators, coal-fired
Identification:	1SGA, 2SGA
Facility:	Intermountain Generating Station Delta, Utah

B. Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation:	40 CFR Part 51
Permit:	AO replacing DAQE-049-02 Title V Operating Permit #2700010002
Emission limits:	
Carbon Monoxide:	1320 lb/hr
Monitoring requirements:	Parametric Boiler Data: Percent O2, OFA Status

C. Control Technology

Good combustion practice (GCP). For purposes of this CAM, GCP means combustion with minimum percent O2 in the boiler exit flue gas so that CO does not exceed 250 ppm. The O2 values vary with over fire air (OFA) operating conditions.

II. Monitoring Approach

The key elements of the monitoring approach are presented in the following table:

TABLE . MONITORING APPROACH

I. Indicator	Percent O2	OFA Service Condition
Measurement Approach	Combustion flue gas percent O2 will be monitored at the exit path of each boiler. CO concentration will then be calculated utilizing O2 values. Conversion from ppm to lb/mmbtu shall be made by incorporating design heat input.	OFA operating condition shall be monitored. Monitoring shall include OFA position and status: i.e., No OFA, 1/3 OFA, 2/3 OFA, full port OFA, throttled or open. OFA status shall determine curve by which CO concentration shall be calculated.
II. Indicator Range	An excursion is defined as an exceedence of GCP, except for start-up, shutdown, planned / maintenance outages, or malfunction. CO concentration will be determined in ppm by calculation of percent O2 against developed curves (attached) for various over fire air operating conditions. Good combustion practice include operating conditions whereby CO concentration does not exceed 250 ppm in the flue gas.	An excursion is defined as an exceedence of the permit limit, except for start-up, shutdown, planned/maintenance outages, or malfunction. CO concentration will be determined in ppm by calculation of percent O2 against developed curves (attached) for various over fire air operating conditions. Good combustion practice include operating conditions whereby CO concentration does not exceed 250 ppm in the flue gas.
III. Performance Criteria A. Data Representativeness[b]	Measurements are weighted average results collected from several sensors located in each boiler exit flue path 4 times per hour.	Operational status is measured by OFA system damper position.
B. Verification of Operational Status	NA	Operational status shall be recorded in the Plant Information system.
C. QA/QC Practices and Criteria	Calibrations shall be maintained within manufacturers recommendations.	OFA system falls under an PM program.
D. Monitoring Frequency	Continuous, compiled weekly.	Instantaneous, compiled weekly.
Data Collection Procedure	Measurements are recorded in PI.	Status is recorded in PI.
Averaging Period	30-day rolling average.	30-day rolling average.

Title V CAM Equivalent Monitoring
Intermountain Generating Station
Main Boiler Carbon Monoxide Emissions

JUSTIFICATION

I. Background

The pollutant-specific emission units are the main boiler steam generators 1SGA and 2SGA. Fossil fuel combustion can generate carbon monoxide (CO). Control of CO is accomplished through utilization of Good Combustion Practice (GCP) which balances boiler performance against environmental parameters, such as nitrogen oxides (NOx) and CO. Testing was performed to determine the relationship between boiler operating parameters and CO emissions. The test curves are attached in support for the following rationales.

II. Rationale for Selection of Performance Indicators

Percent O2 in the boiler exit flue gas was selected as the performance indicator because it is indicative of GCP ranges developed through testing. Testing curves show a direct correlation between percent O2 and carbon monoxide for various operating conditions. When GCP is utilized, CO emissions can be minimized when NOx is also minimized. Decreases in percent O2 correlate to increases in CO, and CO can be calculated based upon percent O2, and then directly compared to permit limits.

III. Rationale for Selection of Indicator Ranges

The selected indicator range for good combustion practice is based upon operating conditions. Those conditions and percent O2 associated with 250 ppm CO are tabled below:

OFA Operating Status	Percent O2 = 250 ppm CO
No OFA	2.0%
1/3 OFA	2.0%
2/3 OFA - throttled	2.0%
2/3 OFA - full open	1.75%

Title V CAM Equivalent Monitoring
Intermountain Generating Station
Main Boiler Carbon Monoxide Emissions

An excursion occurs when 250 ppm CO is exceeded, except for startup, shutdown, planned / maintenance outage, or malfunction. When an excursion occurs, boiler operation will be evaluated to determine the reason of the occurrence and to decide the action required to correct the situation. The evaluation will include a complete re-calculation conversion to lb/mmbtu to determine actual compliance with the permit limit.

All excursions will be documented, and if a conversion is made that indicates an emission of greater than 1320 lb/ based upon a 30 day rolling average, the excursion will be reported. An indicator range of percent O2 relating to 250 ppm CO was selected because: (1) an increase in CO emissions is indicative of a change in good combustion practice; and (2) a monitoring technique which does not require a new CEM installation is desired. Although percent O2 is an indirect measurement for CO, the correlation being used has been tested to provide good determination of CO using percent O2.

IV. Methodology for Determination of CO

The formula for calculating CO in ppm follows the general equation:

$$[C_{ppm}] = n * (O_2\%)^a,$$

where; $[C_{ppm}]$ = concentration of CO in parts per million;
n = curve specific factor;
$O_2\%$ = percent O2 measured at boiler exit;
a = curve specific exponent.

The following table identifies n and a for each OFA operating condition:

OFA Operating Condition	n	a
No OFA	47259	-7.6817
1/3 OFA	66265	-7.9824
2/3 OFA - throttled	4029.2	-4.0112
2/3 OFA - full open	1372.4	-3.0919

Title V CAM Equivalent Monitoring
Intermountain Generating Station
Main Boiler Carbon Monoxide Emissions

The emission limit is verified by the conversion to pounds per hour, calculated as:

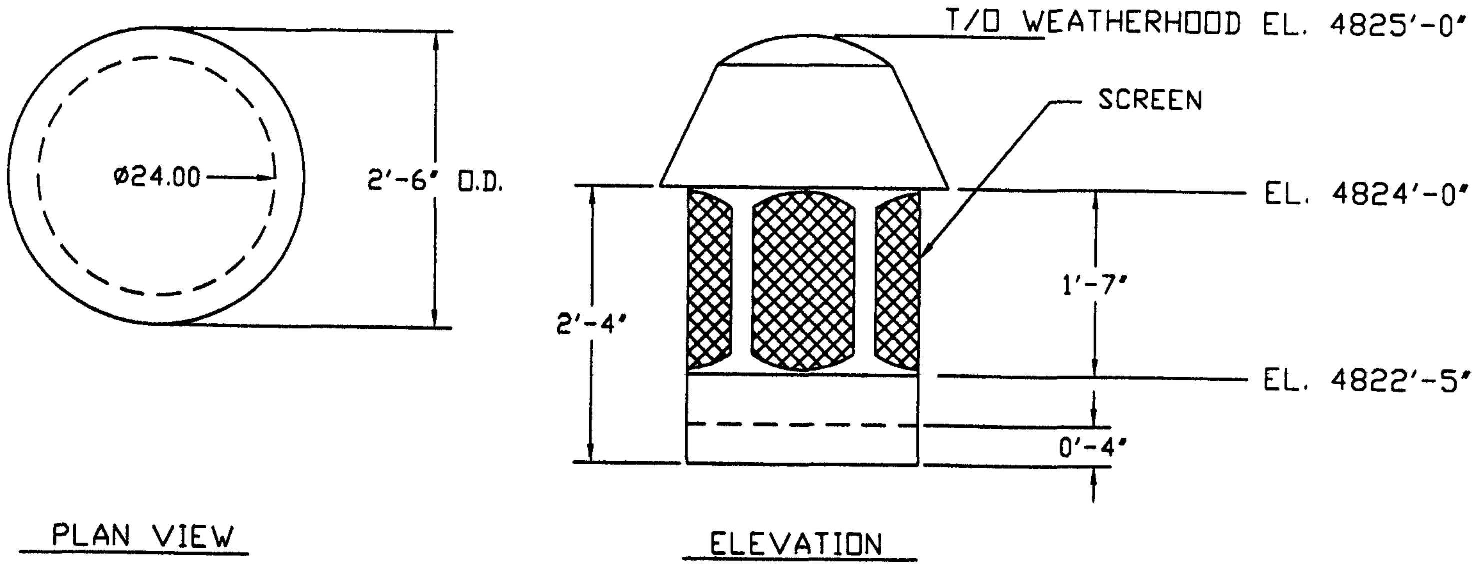
$$[C_{lb/hr}] = [C_{ppm}] * 2.59 * 10^{-9} * MW * Fd * 20.9/(20.9-O_2\%) * H_I$$

where; $[C_{lb/hr}]$ = pound per hour emission rate
$[C_{ppm}]$ = CO concentration in parts per million
$2.59*10^{-9}$ = conversion factor for pound per standard cubic feet
MW = molecular weight of CO
F_d = "F" factor to convert standard cubic feet per million BTU heat input.
$O_2\%$ = excess combustion oxygen, in percent
H_I - heat input, in million BTU per hour

TABLE 1
Recently Issued PSD Permits - CO Limits

Name	Type/Size	CO Limit	Comments
Hawthorne Unit 5 Missouri	Pulverized Coal 570 MW	0.16 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance
Springerville Units 3 and 4 Arizona	Pulverized Coal 450 MW each	0.15 lb/mmbtu (30 day rolling average)	Combustion control CEMS used for compliance
Holcomb Unit 2 Kansas	Pulverized Coal 660 MW	0.15 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance If CO and NOx limit cannot be met simultaneously, State will revise CO limit
Thoroughbred Units 1 and 2 Kentucky	Pulverized Coal 750 MW each	0.10 lb/mmbtu (30 day rolling avg)	Combustion control CEMS used for compliance
Wygen Unit 2 Wyoming	Pulverized Coal 500 MW	0.15 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance
Bull Mountain Roundup Unit 1 Montana	Pulverized Coal 780 MW	0.15 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance
Plum Point Energy Station Unit 1 Arkansas	Pulverized Coal 550 - 800 MW	0.16 lb/mmbtu	Combustion control CEMS used for compliance
Rocky Mountain Power, Hardin Unit 1 Montana	Pulverized Coal 113 MW	0.15 lb/mmbtu	Combustion control CEMS not required Stack test used for compliance
Council Bluffs Energy Center Unit 4 Iowa	Pulverized Coal 750 MW	0.154 lb/mmbtu (1 day avg) 5,177 tpy	Combustion control CEMS used for compliance If CO and NOx limit cannot be met simultaneously, State will revise CO limit

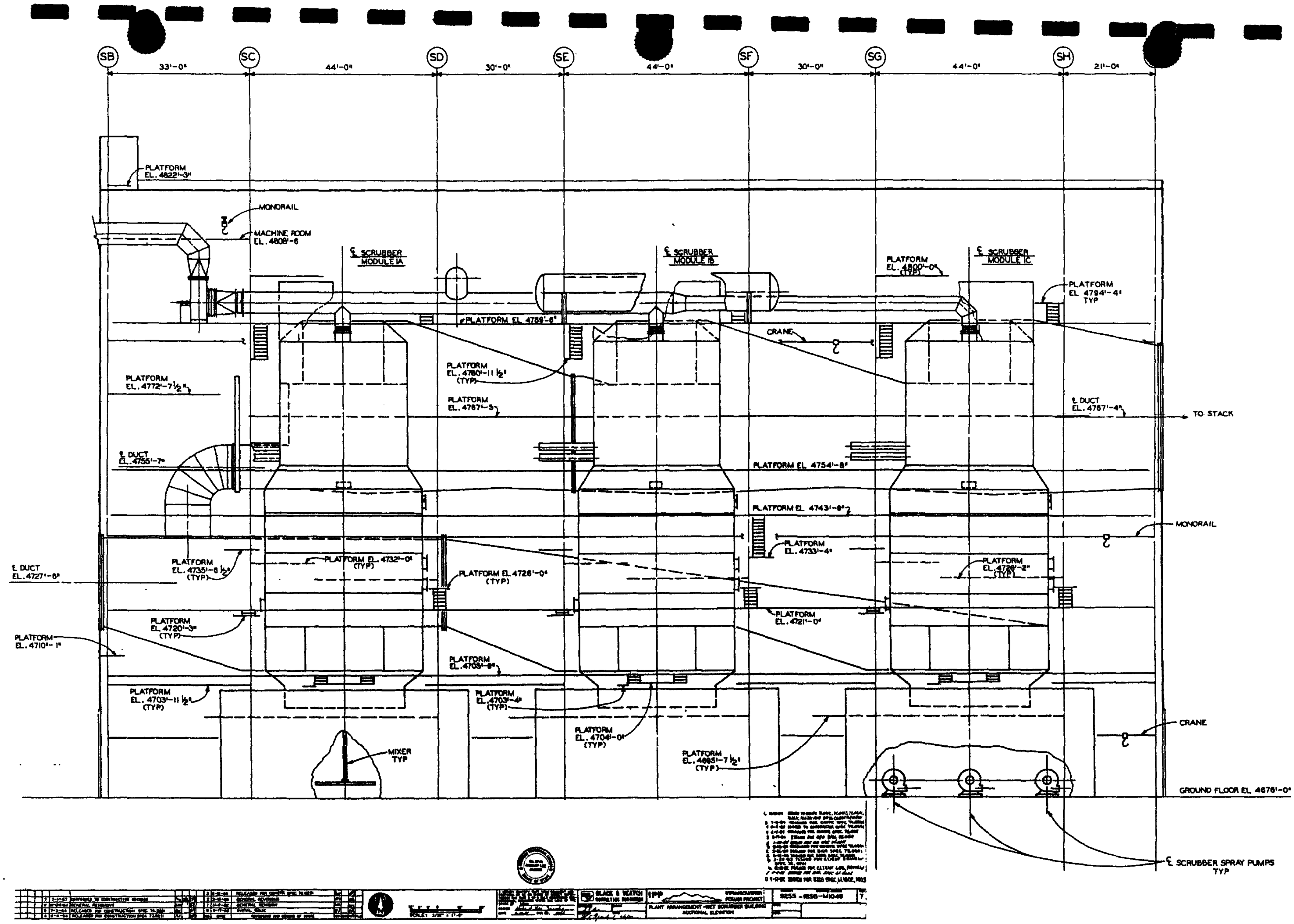
All the permits above, except Bull Mountain Roundup, exempt startup, shutdown and malfunction in the short term (1 hour, 3 hour, 24 hour and 30 day) emission limits.



WEATHERHOOD - REACTION TANK VENT
(TERMINATION ABOVE ROOF)

NOTE:
ROOF ELEVATION VARIES FROM HIGH POINT 4821'-3 3/4" TO LOW POINT 4819'-0".

IP10_003315


SB
SC
SD
SE
SF
SG
SH
33'-0"
44'-0"
30'-0"
44'-0"
30'-0"
44'-0"
21'-0"
PLATFORM EL. 4822'-3"
MONORAIL
MACHINE ROOM EL. 4808'-6
℄ SCRUBBER MODULE IA
℄ SCRUBBER MODULE IB
℄ SCRUBBER MODULE IC
PLATFORM EL. 4800'-0" (TYP)
PLATFORM EL 4794'-4" TYP
PLATFORM EL 4789'-6"
CRANE
PLATFORM EL. 4772'-7½"
PLATFORM EL. 4780'-11½" (TYP)
PLATFORM EL. 4767'-5
℄ DUCT EL. 4767'-4"
TO STACK
℄ DUCT EL. 4755'-7"
PLATFORM EL 4754'-8"
PLATFORM EL 4743'-9"
MONORAIL
PLATFORM EL. 4733'-4"
℄ DUCT EL. 4727'-6"
PLATFORM EL. 4735'-6½" (TYP)
PLATFORM EL. 4732'-0" (TYP)
PLATFORM EL 4726'-0" (TYP)
PLATFORM EL. 4726'-2" (TYP)
PLATFORM EL. 4720'-3" (TYP)
PLATFORM EL. 4721'-0"
PLATFORM EL. 4710'-1"
PLATFORM EL. 4705'-6"
PLATFORM EL. 4703'-11½" (TYP)
PLATFORM EL. 4703'-4" (TYP)
PLATFORM EL. 4704'-0" (TYP)
PLATFORM EL. 4695'-7½" (TYP)
CRANE
MIXER TYP
GROUND FLOOR EL 4678'-0"
℄ SCRUBBER SPRAY PUMPS TYP
BLACK & VEATCH
IPP
POWER PROJECT
PLANT ARRANGEMENT - WET SCRUBBER BUILDING SECTIONAL ELEVATION
9255-1858-M1046
SCALE: 3/32" = 1'-0"
RELEASED FOR CONSTRUCTION
GENERAL REVISION

IP10_003316

DRIFT Calc for Scrubber Reaction Tank Vents

Average Slurry Total Percent Solids:	15	%
Average TDS	90	g/L
Vent flow	2500	cfm
Drift Carry	1.87443E-06	lb/cf
Evap Rate	0.004686063	lbs/min
PM10 fraction(90g/L / 1000000)	0.09	ppm convert
PM10 Emission Rate =	**0.025304739**	**lbs/hr**
	0.110834759	**tons/yr (per vent)**
	0.886678068	**tons/yr (total)**

DERIVE: DRIFT (evaporation)

USING: q=AK*(MwPv/RT), where
q = rate of evaporation (kg/s)
A = surface area (m2)
K = ratio of specific heats @1atm (=0.0025Us^0.78[18/Mw}^1/3)
Us = surface wind speed
Mw = molecular weight (kg/kmole)
Pv = vapor pressure (N/m2)
R = 8.314x10^3 J/(deg)kmole
T = temperature, K

GIVEN	Dimension - English		Dimension - metric	
Reaction Tank Diameter =	60	ft	18.288	m
Vent Diameter =	30	in	0.762	m
Volume Flow	2500	cfm	1.179875	m3/s
Optg Temp	51	C	324	K
Vapor Press - Water	100	mmHg	13332	N/m2
Molecular Wt - Water	18	g/mole	18	kg/kmole

CALC				
Surface Wind Speed =	0.014744	ft/s	7.49001E-05	m/s
Area =	2826	ft2	262.543991	m2
Evap Rate =			3.54039E-05	kg/s

IP10_003317

INTERMOUNTAIN POWER SERVICE CORPORATION

September 24, 2003

Mr. Richard Sprott, Director
Division of Air Quality
Utah Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Attention: Nando Meli, Jr., New Source Review Section
RE: Experimental Approval Order: DAQE-AN0327012A-03

Dear Director Sprott,

Experimental Approval Order to Install and Test Over Fire Air: REPORT

The Intermountain Generating Station (IGS) has installed, tuned, and tested an over fire air system for NOx control under the authority of Approval Order (AO) DAQE-AN0327012A-03 issued by the Division of Air Quality (DAQ). The Intermountain Power Service Corporation (IPSC) is hereby submitting the results of the testing as required in the above referenced AO.

BACKGROUND

On February 5, 2003, IPSC submitted a Notice of Intent requesting approval to install and test an over fire air (OFA) system on Unit 1 for NOx control. Testing results are intended to be used to establish permitting parameters for installing another OFA system on Unit 2 and the full time operation of both systems. The IGS is a coal-fired, steam electric plant located in Millard County.

The OFA was installed and tested to ascertain the operating characteristics and environmental aspects of good combustion practice that minimizes carbon monoxide (CO) emissions while simultaneously controls NOx emissions. It was expected that the use of OFA could increase CO emissions by a net significant amount (100 tons per year) as NOx emissions are reduced. The results of the testing will help DAQ and the IPSC to determine permit conditions that represent the Best Available Control Technology (BACT) for CO when the OFA is utilized.

The DAQ issued an experimental approval order, DAQE-AN0327011-03, on February 14, 2003, granting the installation and testing of OFA. That AO was replaced by DAQE-AN0327012A-03, on May 27, 2003, to make certain corrections. The approval order outlines the conditions under which the testing could occur. This letter serves as the report required by the AO.

850 West Brush Wellman Road, Delta, Utah 84624 / Telephone: (435) 864-4414 / FAX: (435) 864-6670 / Fed. I.D. #87-0388573

TEST SUMMARY & APPROVAL ORDER COMPLIANCE

OFA was installed in the Unit 1 boiler during its Spring outage. Initial operation of the OFA system upon restart of Unit 1 was problematic inasmuch as impacts to air flow within the boiler were significantly disrupted. It took significant time and effort to troubleshoot and pinpoint the causes, which included both mechanical breakdown and uneven fuel and air flows.

Once the causes were identified and corrected, tuning the OFA system to operate satisfactorily pursuant to its design began. Once the OFA system performance was optimized, IPSC performed environmental testing to identify specific emission characteristics in various states of operation. That testing occurred September 6 - 9, 2003, and all testing data, along with pre-construct test data, are included with this report. The pre-construct testing occurred prior to the Spring outage when OFA was installed in order to obtain baseline information.

The approval order was issued contingent upon compliance with seven conditions to be followed during the test burn. See page 2 of DAQE-AN0327012A-03. Those conditions and compliance status are outlined below. Please note that Debbie Olsen of your office reviewed and verified compliance with the conditions listed in the AO.

1. The test operation of the overfire air (OFA) system was only performed in the Intermountain Generating Station located in Delta, Utah.

2. During the test period the OFA was operated only on the Unit 1 boiler.

3. This Experimental Approval Order replaced the Experimental AO DAQE-AN0327011-03 dated February 14, 2003. (No compliance requirement.)

4. The trial test operations of the OFA will not be performed more than 180 days from the date of this Experimental Approval Order (AO).

5. All requirements of AO DAQE-049092, dated January 11, 2002, and the Title V permit #2700010001 were adhered to during the testing period.

6. The test operation of the OFA system was to be terminated if the emissions and/or opacity limits listed in the AO DAQE-049-02 for the Unit 1 were exceeded. Since such was not the case, OFA testing was not terminated for those reasons.

The seventh requirement was to provide this report, including emissions results covering emissions measured, damper positions, mass airflow, and all other measurements taken that are affected by the OFA system. We have included with this letter an Excel spreadsheet diskette in electronic format containing these required data. The file includes worksheets of various information. Those worksheets containing test data are described here:

1. Unit One Data Master. This worksheet contains all compiled pertinent operating and test data for the testing period.
2. Unit One Critical Data. This worksheet provides the operating and test data specific to CO determinations.
3. Unit One Summary Table. This worksheet summarizes test results.
4. Pre-Construct Data. This worksheet provides test data prior to OFA installation to provide baseline information.
5. Pre-Construct Summary Table. This worksheet summarizes pre-construct test results.

The other files contained on the diskette apply to further permitting. Additional test analysis will be provided under separate cover to the NSR review engineer responsible for permanent permitting of the OFA system and operation. This analysis will project emissions from various operating scenarios, as will as make predictions from which permit conditions may be derived.

If you require any further information concerning the testing of OFA or issues tied to this approval order, please contact Mr. Dennis Killian, Superintendent of Technical Services at IPSC, at 435-864-4414, or dennis-k@ipsc.com .

Cordially,

George W. Cross

George W. Cross
President and Chief Operations Officer

BP/RJC/co

Enclosures: Data Files
cc: Blaine Ipson
Lynn Banks
Jerry Hintze
Eric Tharp, LADWP

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Section I: Introduction and Objectives

1.1 Study Objectives

In March 2003, an Over Fire Air (OFA) system was installed in the boiler of Unit 1 at the Intermountain Generating Station (IGS). The OFA system was installed to control NO_X (nitrogen oxides) emissions with varying and worsening coal qualities. A poorly designed or improperly operated OFA system has the potential of generating high carbon monoxide (CO) emissions while still achieving the desired reductions in NO_X emissions. This report, and the proceeding testing, has been completed primarily for the Utah State Division of Air Quality and it has the following objectives:

1. Determine if the OFA system installed on IGS Unit 1 has been properly designed and can be operated within acceptable CO limits while still achieving the desired NO_X reduction.

2. Establish the operating range in which the system may be operated while still maintaining acceptable CO and NO_X emissions.

1.2 Overview of the Intermountain Generating Station

The IGS, located in Millard County, Utah, consists of two, coal fired, electric generating units, designated Unit 1 and Unit 2. Unit 1 currently operates with a full load rating of 950 MWG and Unit 2 operates with a full load rating of 900 MWG. The boiler burns pulverized coal in an opposed wall burner arrangement with balanced draft. Particulate emissions are controlled with fabric filters and SO_2 with wet limestone scrubbers. Most of the coal is received by unit trains with some by truck. Unit 1 went into service in 1986 and Unit 2 in 1987.

1.3 IGS Uprate Project

In 2001, Intermountain Power Service Corporation (IPSC) undertook a series of modifications to raise the operating load rating on both units to 950 MWG. The plan included modifications to improve environmental compliance equipment so that the new higher load could be achieved without a significant increase in regulated emissions. The modifications consisted of the following projects:

- New High Efficiency HP Turbine Section
- Helper Cooling Tower
- Transformer and Iso-Phase Bus Duct Cooling
- Increase Boiler Safety Relief Capacity
- Increase Circulating Water Make-up
- Increase Boiler Feed Pump Capacity
- Heater Drain Line Modifications
- Scrubber Modifications to Increase Removal Efficiency

In March 2002, some of these modifications were completed on Unit 2 and its load was increased to 900 MWG. The 900 MWG full load rating on Unit 2 was achieved with only a small increase in heat input into the boiler due to the increased HP turbine efficiency. The remaining projects for 950 MWG full load rating will be completed on Unit 2 in March 2004.

In March 2003, all of the modifications were completed on Unit 1 and the full load rating was changed to 950 MWG.

Section II: Theory of CO and NO_X Formation and Control

2.1 NO_X Formation

Combustion of any fossil fuel generates some level of NO_X due to high temperatures and the availability of oxygen and nitrogen from both the air and fuel. Combustion of pulverized coal can release this nitrogen as "nitrogen oxides" (NO_X) but whereas sulfur in coal produces SO_2 almost stoichiometrically, there is more than one possible nitrogen combustion product. Conversion to NO_X is incomplete; species such as nitrogen itself (N_2), nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O) are among the other possible products of a complex process involving many different and competing reactions during combustion.

Thermal NO_X refers to the NO_X formed through high temperature oxidation (>1540^0 C)[1] of the nitrogen found in the air. The formation rate is a strong function of temperature as well as the residence time at temperature. Thermal NO_X formation is typically controlled by reducing the peak and average flame temperatures.

The major source of NO_X emissions from coal is the conversion of the fuel bound nitrogen to NO_X during combustion. Laboratory studies[2] indicate that fuel NO_X contributes approximately 80 percent of the total uncontrolled emissions when firing coal. Nitrogen found in coal is typically bound to the fuel as part of the organic compounds. During combustion, the nitrogen is released as a free radical to ultimately form NO_X. Although it is a major factor in NO_X emissions, only 20 - 30 percent of fuel bound nitrogen is converted to NO_X. Conversion of fuel bound nitrogen to NO_X is strongly dependent on the fuel/air stoichiometry but is relatively independent of variations in combustion zone temperature. Therefore, this conversion can be minimized by reducing oxygen availability during the initial stages of combustion.

2.2 Factors Affecting NOx Formation

There are many factors that can affect both fuel and thermal NO_X formation in the boiler. By far, the largest factor is the availability of air during the first stages of combustion. All NO_X combustion control techniques center around controlling this factor. However, these other factors may have some effect on the NO_X formation:

- Coal characteristics.
- Pulverizer performance.
- Boiler cleanliness.
- Operator and control system actions.
- Ambient conditions.

2.3 Air Staging During Combustion to Control NO_X

The most effective means of reducing fuel-based NO_X formation is to reduce oxygen (air) availability during the critical step of devolatilization. Additional air can be added

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1. Steam Its Generation and Use, 46th Edition, Babcock & Wilcox

2. How Coal Properties Influence Emissions, IEA Coal Research

later in the process to complete char reactions and maintain high combustion efficiency. Oxygen availability can be reduced during devolatilization in two ways. One method is to remove a portion of the combustion air from the burners and introduce it elsewhere. This is how an OFA system works. It takes air from the burners and reintroduces it later in the combustion process above the burner rows. The second method is by burner design. The burner can be designed to supply all of the combustion air but to limit its rate of introduction to the flame. Only a fraction of the air is permitted to mix with the coal during devolatilization. The remaining air is then mixed downstream in the flame to complete combustion. With a low NO_X burner, overall mixing is reduced and the flame envelope is large compared to rapid mixing conventional burners.

2.4 CO Formation

During an ideal combustion process, the carbon in the coal would be oxidized through a series of reactions to form Carbon Dioxide (CO_2). In the real world, a small fraction of the combustion process is halted before it is completed and some Carbon Monoxide (CO) is formed.

Theoretically, all large coal fired boilers should operate with complete combustion and no CO emissions because there is generally 10 - 25 percent excess air over that required for stoichiometry. Unfortunately, coal boilers are large and complex and many factors can interrupt the combustion process in isolated and varying areas of the boiler creating small levels of CO emissions at the stack discharge. The areas where CO is generated are characterized by air levels below stoichiometry and CO emissions can be reduced by balancing air and fuel flows. Just one burner at substoichiometry can greatly increase the amount of CO in the entire boiler. For this reason, air and fuel flow balancing to each burner is a critical first step in proper combustion and CO reduction.

2.5 CO and Over Fire Air

As discussed earlier, NO_X emissions can be lowered by reducing the amount of excess air during the initial stages of combustion. This is how OFA works. It takes air normally entered at the burner and reintroduces it above the burner zone when the nitrogen molecules have become more stable. Unfortunately, removal of air from the burner zone can result in increased CO emissions, particularly if the air flow drops below stoichiometry at the burners. On the positive side, the ignition energy in the gas stream (>788° C for combustion of CO)[3] is still high enough in the area of the OFA ports that when the CO contacts the entering air it will combust to form CO_2. To insure the lowest CO emissions possible with OFA, the air nozzles in the boiler should be designed so that the entering air velocity is sufficient for complete penetration of the boiler cross section.

A properly designed and operated boiler with OFA should still have reasonable CO emissions. However, if total excess air in the boiler is too low or if the percentage of air going to the OFA ports is too high, even with properly balanced fuel and air, the burners can go substoichiometric and the total amount of CO generated will overwhelm the air entering through the OFA ports or CO will slip around the outside of the air curtain. The definition of "Good Combustion Practices" for a boiler equipped with OFA is to find the levels of total excess air with a specified percent of air to the OFA system that will

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[3] Steam Its Generation and Use, 46th Edition, Babcock & Wilcox

give the required NO_X reduction with reasonable CO generation. This principle is demonstrated in Figure 2-1.

2.6 Volatile Organic Compounds and Ash Loss-On-Ignition

Other indicators of poor combustion in the boiler would be the presence of Volatile Organic Compounds (VOCs) in the flue gas and high fly ash Loss-On-Ignition (LOI). VOCs are generated when the coal is allowed to reach devolatilization temperature but, not high enough nor in the presence of enough oxygen to combust. However, large coal fired boilers operate at very high temperatures and there are large amounts of excess air making it very unlikely that large amounts of VOC's would be generated. Even though some increase in VOC's might be expected with an increase in CO emissions, the overall emissions will remain very small due to the low combustion temperatures of VOC's (275° to 386° C)[4]. If air entering through the OFA ports combusts the CO generated at the burner front, it will certainly combust almost all of the VOC's with their much lower combustion temperature.

When a coal particle is burned in a boiler, it leaves behind a small residual amount of combustible materials in the ash. These combustible materials may be many compounds but are generally just considered to be carbon[5]. If the ash is reheated again to combustion temperatures and the carbon is allowed to combust, the percent reduction in mass of the total ash is called LOI and is a measurement of combustion efficiency in the boiler. Typical ash LOI numbers for coal fired boilers can vary between 10 - 0.2 percent depending on the coal quality and the size and type of burner. Any form of combustion NO_X control will increase the amount of combustibles in the ash. It is also true that an increase in CO emissions probably would indicate an increase in LOI. However, there are no consistent relationships between the two from which to derive the value of one from the other.

2.7 Effects of Coal Quality on CO and NOx

Currently, the coal received and consumed at IGS comes from coal fields located in the Price, Utah, area. It is bituminous, low-sulfur, high BTU coal. The BTU content of each of the mines is relatively consistent but, some of the other characteristics are not. Also, variations can be seen just from changes of locations within the same mine and it is often difficult to know what to expect.

The main coal factors affecting NOx emissions are[6] nitrogen and volatiles. Of course, higher fuel bound nitrogen means the potential for higher NOx exists. Not so obvious is the percent volatiles, lower volatiles most likely indicates higher NOx potential. Many studies have comfirmed these to be the two best predictors of NOx emissions from a given coal source but, no single group of variables has been completely consistent in predicting NOx emissions from a coal source. There are just too many variables for consistent accuracy. Other coal properties affecting NOx emissions could be moisture content, ash content and bound oxygen. Most of these same factors and others could also affect the amount of CO generated. For this reason, any definition of "Good Combustion" should have enough range to allow for variations in coal quality.

---

4 L. Douglas Smoot PhD, Brigham Young University

5 Steam Its Generation and Use,46th Edition, Babcock & Wilcok

6 How Coal Properties Influence Emissions, IEA Coal Research

Definition of Good Combustion

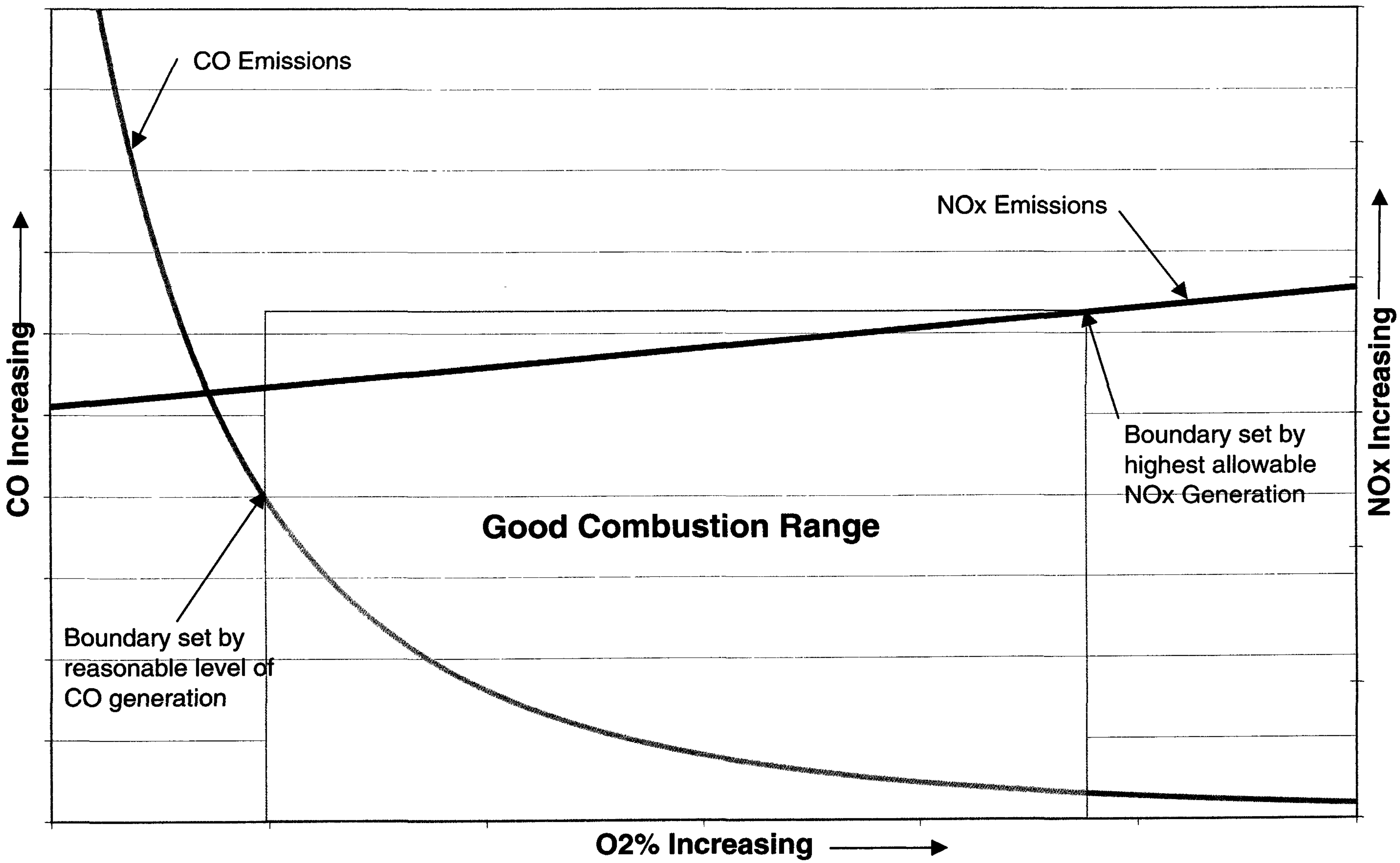


Figure 2-1, Definition of Good Combustion

IP10_003329

Section III: IGS NO_X and CO Control Equipment Design and Anticipated Performance

3.1 Equipment Description

Control of NO_X at IGS is accomplished with the following equipment:

- **Low NO_X Burners:** The Dual Register Burner (DRB) style Low NO_X Burners (LNB's) designed and provided by Babcock & Wilcox (B&W) during original construction have provided stable and reliable combustion and emissions performance. The Intermountain steam generators are designed with 48 LNB's in an opposed-wall configuration. Combustion air is provided to the burners from compartmentalized, double-end fed windboxes controlling air to individual rows of burners installed on the front and rear walls. Each burner is equipped with outer and inner air control to balance air across each burner row.

  Due to failures from thermal fatigue, the Unit 2 B&W DRB burners are scheduled for replacement in March 2004, pending approval and permitting. The new burners will be latest technology, high differential, LNB's manufactured by Advanced Burner Technology, Inc. (ABT) of Bedminster, New Jersey. ABT has established a track record in the power industry of superior performance (see Appendix, Section A-2). The new burners will be designed for the same capacity as the existing burners.

- **Over Fire Air System:** An Over Fire Air (OFA) system manufactured by Babcock Power Services, Inc. (BPI) was installed on Unit 1 in March 2003 and is scheduled for installation on Unit 2 in March 2004, also with approval and permitting. BPI is an international designer/installer of power boilers and appurtenances. BPI, previously known as Babcock Borsig, Inc., DB Riley etc., has extensive experience in OFA and general boiler design. An OFA system experience list for BPI is shown in the Appendix, Section A-2.

  The OFA system consists of a set of 16 air ports installed on the front and rear furnace walls above the existing six burner columns. One additional port is installed near each sidewall to ensure optimal air distribution. A dedicated combustion air duct feeds air from the forced draft duct directly to the double-end fed, flow controlled OFA duct. The individual OFA ports are equipped with side-to-side, split-range flow control to allow 1/3, 2/3, or full port flow depending on combustion requirements.

3.2 Fuel and Air Flow Balancing

Several years ago, extensive balancing of both the primary and secondary air flows was completed on both units and prior to the Unit 1 outage we had no reason to believe that it had changed significantly. When Unit 1 was returned to service after the outage, we noticed that the OFA installation had disrupted both the fuel and air (primary and secondary) flows and they were out of balance.

To correct this problem, a full fuel and air balance regimen has been completed on Unit 1 in preparation for the OFA performance testing. The overall objective was to present each burner with an approximate stoichiometric ratio of fuel and air leaving as much air as possible to inject through the OFA ports to insure coverage of the boiler cross section. The primary air lines were balanced empirically using "dirty air flow measurements" of the flow in each burner line. "Dirty Air Flow Measurements" consist of measuring both the coal and fuel in the burner supply lines and balancing each. Adjustments were then made to new balancing dampers in each coal line installed after the outage for this testing (see Appendix, Section A-3 for balance data). The secondary air was balanced through observations of the flame wall separation and shape while the unit was in service and by cross sectional measurements of CO in the flue gas at the economizer outlet.

The result of the balancing is that the combustion process occurs initially in an air-lean environment reducing the formation of NO_X from fuel bound nitrogen sources. Additionally, the OFA ports are arranged and designed to blanket the upper furnace with a cooling layer of combustion air that further inhibits the formation of NO_X while still providing enough air and energy to burn out the CO.

3.3 OFA Design Parameters

Under the terms and test conditions specified in the contract, BPI provided a performance guarantee for emissions of both CO and NO_X at full load operating conditions as follows:

- NO_X: .37 lb/MMBTU
- CO: 100 ppm

Full load conditions are defined within the specification as follows (these are design values only and do not represent actual operating conditions):

▸ Superheat Outlet Temperature	1005° F
▸ Reheat Outlet Temperature	1005° F
▸ Total Air % Stoichiometry	118% (approx. 2.5% O_2)
▸ Coal Fineness (Min.% thru 200 Mesh)	70%
▸ Coal Fineness (Max. % on 50 Mesh)	1%
▸ Pulverizers In-service	7
▸ Boiler Surface Cleanliness	80-85%
▸ Furnace Surface Cleanliness	85-90%
▸ Superheat Attemperator Flow (Min.)	50,000 lbs/hr
▸ Reheat Attemperator Flow	0 lbs/hr

3.4 OFA System Boiler Model

Under separate contract, a boiler model was completed with GE Energy and Environmental Research (GE-EER)as an independent verification of BPI's design parameters.

One of the key recommendations resulting from the operation of the GE-EER combustion model focused on OFA penetration into the furnace. The model showed that under certain operating modes, 10 percent OFA may not be sufficient to ensure proper O_2 distribution throughout the boiler cross-section. This led to our upgrading the standard, manual OFA port control provisions to allow for independent, side-specific, remote control of the 1/3 and 2/3 damper sets. This gives us greater response capability with varying loads and mill configurations to bias the OFA distribution for minimizing emissions. Several graphs of the various model runs completed in this analysis are shown in the Appendix, Section A-4.

The model predicted NO_X emissions reduction from OFA as summarized in Figure 3-1, Predicted NO_X Emissions GE-EER Model.

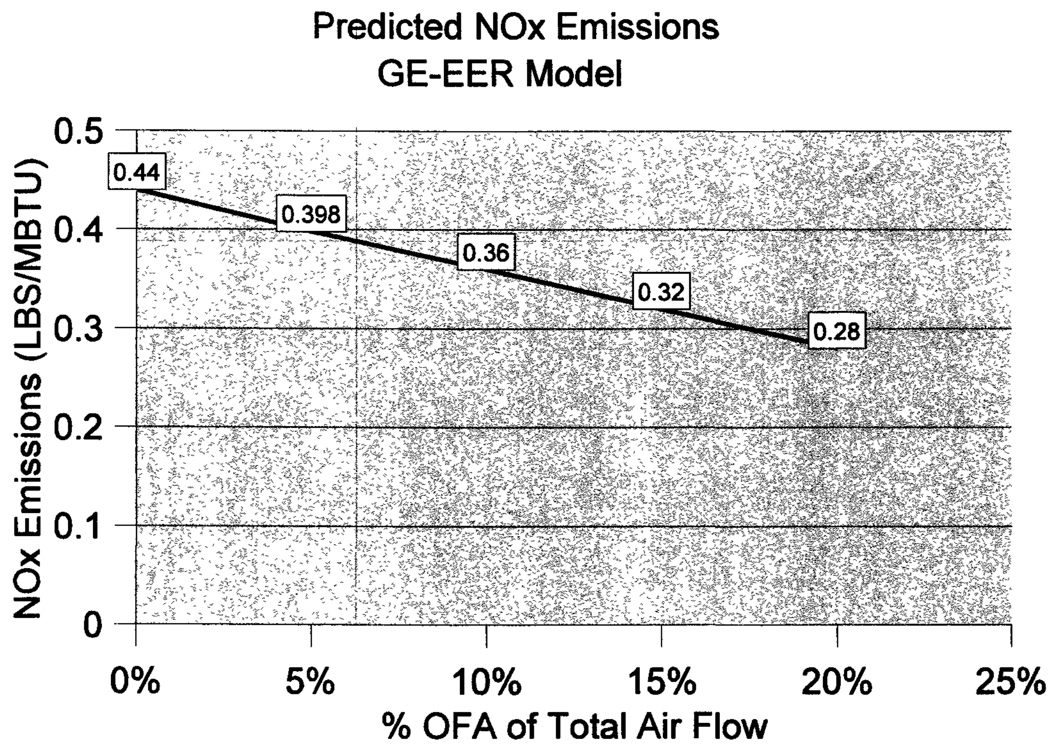


Figure 3-1, Predicted NOx Emissions GE-EER Model

The results of the model coincided closely with the guaranteed performance from BPI in their contract with 0.37 Lbs/MBTU with 10 percent OFA at 950 MWG.

The model also predicted the effect of OFA on CO emissions as summarized in appendix, Section A-5. GE predicted much higher CO emissions than as guaranteed by BPI. The discrepancy between the two centered mostly around the belief GE-EER had that BPI's OFA nozzles would not cause the air to distribute across the full cross section of the boiler allowing large flow paths for CO to pass and cool below ignition temperature before full combustion.

They also did a prediction on the increase in ash LOI change as a result of OFA as shown in Figure 3-3, Ash LOI Increase GE-EER Model.

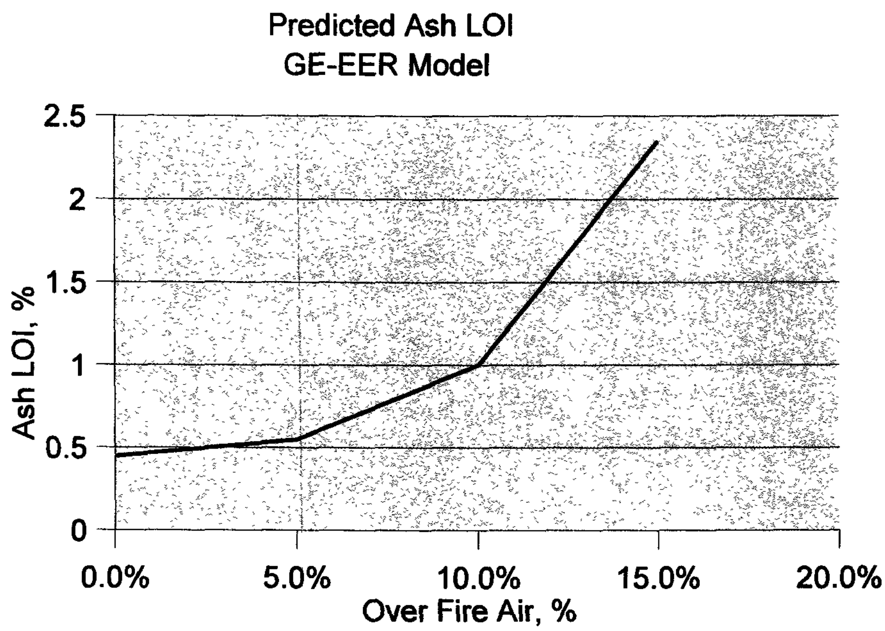


Figure 3-3, Ash LOI Increase GE-EER Model

Section IV: Test Methods and Procedures

4.1 General Description

The test methodology for flue gas analysis was conducted in accordance with the general procedures outlined in the ASME PTC 4.1 Steam Generators and PTC 19.10 flue and Exhaust Gas Analysis. Plant instrumentation, where possible, was utilized for the tests supplemented by additional rented equipment. Calibrated gas analyzers were connected to test probes inserted into test taps on the ductwork to obtain samples for the analysis of flue gases. The flue gas samples were mixed, chilled, dried and filtered before analysis.

During the test series, each test point was unique with varying OFA flow (four different configurations) and O_2 levels (five different operational points) to establish needed CO and NO_X levels. Each test was one to three hours in duration (with one hour of very stable conditions). Coal samples were taken during each test period. Prior to the start of each test, fly ash hoppers were emptied. At the end of each test period, fly ash samples were collected. Between each test period, operating variables were changed and soot blowing completed to maintain target main steam and reheat temperatures. Operational changes and stabilization took anywhere from one-half hour to one and one-half hours.

4.2 Test Conditions

A summary of the test conditions and results can be found in the Appendix, Section A-6, OFA Test Conditions. Each test was conducted for a nominal one and one-half to two hour period. The target was to achieve one hour of stable operating data. Some tests were lengthened in duration to achieve that goal.

The coal source and supply were kept consistent by Operations during the test series to ensure emission variations were not a result of changes in fuel quality.

4.3 Data Collection

Test data collection consisted of information from the following sources and locations:

1. Plant data was utilized and collected from the data historian on the PI system which collects data from the Foxboro Digital Control System and Information Computer.

2. A flue gas test grid was established at the boiler economizer outlet utilizing rented high precision flue gas analyzers to measure O_2, CO, NO_X, and CO_2.

3. A flue gas probe, sampling system and analyzer were placed at the stack to collect CO readings (most homogenous location for measurement).

4. Field data collection points and Observations

5. Coal and flyash sample collection and analysis

6. CEM emissions data collected by flue gas probe at the stack

PI (plant information historian) was collected electronically every 30 seconds and the Test Grid data was collected electronically every 20 seconds. CEM data is summarized and made available on 15 minute intervals.

Coal samples were collected every 10 minutes from each of the seven coal feeders during the course of the test. Fly ash samples were collected at the completion of each test, while Operations was emptying fly ash hopper levels for setup on the following test.

4.4 Flue Gas Test Grid at the Economizer Outlet

The flue gas test grid was setup at the boiler economizer outlet duct, which can be accessed on the 11th floor. Fourteen test probes (seven per side) are utilized, and each probe assembly actually has four probes at four different depths. This arrangement establishes a grid array with twenty-eight points per side, with a total of fifty-six points. Reference Test Grid Layout.

Each individual sample point is plumbed to a clear Plexiglas bubblier (so one can visually observe sampling flow rates) where it mixes with the other gas samples on its side. The water bath initially mixes, cools, and filters the flue gas. The sample is then chilled in an ice bath with a knockout bottle (where the condensate is collected), run through a vacuum pump, desiccant filter (moisture removal) and then sent through an air filter (dust removal). The flue gas samples are then plumbed to the gas analyzers where they are slipstream sampled via a flow regulator per each individual analyzer's own requirements. East and West side gas samples are then analyzed separately using rented equipment for CO (two separate analyzers with low and high ranges), O_2, CO_2, and NO_X. The data is collected via a Data Acquisition System (DAS) and stored on a computer and saved to a spreadsheet. This basic arrangement was also used for individual point profiling of the economizer outlet duct for burner tuning purposes. Reference Test Instrumentation List for detailed listing of the flue gas analyzers, Appendix, Section A-7.

4.5 CO Analyzer at the Stack

Additionally, a CO analyzer was rented and stationed at the stack to analyze averaged flue gas conditions at the 355-foot level. This is the same level that the flue gas points are sampled for the CEM analyzers. The gas sample was extracted via a probe from the duct and run through a double chiller and then sent to a low range CO analyzer. This generally follows procedures found in 40 CFR Part 60, Appendix, Reference Method 10.

4.6 Coal Samples

Coal samples were collected throughout the test period from each of the seven pulverizer coal feeders. Special coal sample test taps were installed above each feeder inlet just below the coal silo down spout to get representative test samples. Coal sample size was approximately three quarts, taken from each of the seven feeders. This totaled five gallons which was then sealed and taken to the IPSC coal lab.

Proximate and ultimate coal analysis was conducted by IPSC's in-house coal lab following ASTM procedures.

4.7 Fly Ash Samples

Fly ash samples were collected from most of the performance tests. The fly ash system was out of service for routine maintenance durng several test periods. ISG (fly ash contractor) collected the fly ash samples. IPSC Operations pulled down the hoppers prior to each test period (beginning of each day) and between each test period.

Fly ash analysis was performed both by ISG utilizing a loss on ignition (LOI) abbreviated test and by IPSC utilizing ASTM standards for unburned carbon content.

4.8 Quality Assurance

Test analyzers at the stack and economizer outlet were calibrated at the beginning and end of each test series (day). Calibration gases were primary gas standards. Calibrations on station instrumentation were completed prior to the testing. Coal feeders were rotated out of service two weeks prior to the test to conduct restrictor installation and feeder calibrations. Station O_2 probes were calibrated on a weekly basis during the testing. Three analyzers were replaced prior to the testing. Reference Appendix, Section A-8.

4.9 Test Personnel

All testing was conducted by IPSC Engineering Services personnel. The Test Coordinator was Aaron Nissen, Engineering Supervisor. Mr. Nissen is a licensed Professional Engineer (PE) with the state of Utah and has 23 years of utility performance testing related experience.

Test Coordinator:
    Aaron Nissen, Engineering Supervisor, PE

Analyzers & Test Grid:
    Garry Christensen, Senior Engineer, PE
    Rob Jeffery, Senior Analyst

Technical Support & Coal Sampling:
    Dave Spence, Senior Engineer, PE
    Bernell Warner, Draftsman

Flyash Sample Collection – ISG:
Rod Hansen, Rick Fowles, Kurt Aldredge

OFA System Controls and Dampers:
Ken Nielson, Senior Engineer, PE
Phil Hailes, Engineer

Babcock Power, Technical Support:
Dan Coats, Senior Field Engineering Manager

Section V: Test Results

Tabular results of the testing can be found in the Appendix, Section A-9. Graphical results of the testing can be seen in Figures 5-1 through 5-8.

5.1 NO_X Emissions

The graph (see Figure 5-1) generated from the test data, indicates that without OFA, NO_X emissions would exceed the current permit limit of 0.461 lbs/mbtu when the excess air levels are greater than 3.1 percent O_2 (no test data was actually obtained at this level, graph was developed using points below the permit limit). Since we prefer to operate with excess O_2 at 3 percent or greater for efficient combustion, this validates the need for installation of the OFA system. NO_X reduction without OFA was achieved with lower excess O_2 levels but, it was done at the expense of CO emissions and fly ash LOI's.

Figures 5-2 through 5-4 show the results through varying levels of percent OFA flow; Figure 5-4 at 14 percent flow through the OFA ducts which represents the maximum amount of OFA air. Even though both the 1/3 and 2/3 dampers could theoretically be opened at the same time, early operating experience showed that opening both sets of dampers would only reduce duct pressure and reduce the penetration of OFA into the boiler cross section. Figure 5-5 shows that NO_X reduces linearly with the percent of OFA indicating that the best mode of operation for NO_X control is the maximum amount of OFA at full load conditions. Figure 5-5 corresponds very closely to that expected by both BPI and GE-EER in their design and modeling calculations.

Figure 5-6 shows the relationship of NO_X emissions with percent of OFA air at varying levels of excess air. This graph shows that NO_X decreases with lower excess air and higher percent of OFA. The line for 3.5 percent excess air appears to indicate better NO_X reduction than that of 3.0 percent but, that is against all theory, logic and prior testing and is probably a test anomaly.

Figure 5-4 has an extra NO_x line added to show how coal properties can affect NO_x generation. "Coal Reserve A" is from one of our main suppliers and was used for most of our testing for consistency purposes. "Coal Reserve B" is also from a main supplier and has coal properties similar to that of "Coal Reserve A". However, small variations between them have historically shown large differences in NO_x generation. To make matters more confusing, sometimes "Coal Reserve A" is worse than "Coal Reserve B" making blending to lower NO_x almost impossible. The green shaded area on Figure 5-4 shows the "Good Combustion Range" for "Coal Reserve B" for that test period and indicates the need for flexibility in setting CO limits so that low O_2 operation can be used if needed to maintain NO_x emissions with varying fuel conditions.

5.2 CO Emissions

As expected, Figure 5-1 shows that CO increases dramatically as total excess air is reduced. The relationship between CO and O_2 appears to be exponential and the shape of the curve matches GE-EER's model and reference books on the subject (see Appendix, Section A-10).

Comparison of Figures 5-1 through 5-4, shows that as the percent of OFA flow increases beyond 10 percent, the exponent of the curve decreases, somewhat flattening out the curve of CO generation in the area of our normal operation. This decreasing of the exponent indicates that CO becomes less sensitive to O_2 levels with higher levels of OFA flow. This is probably the result of the reburn of the CO at the level of the OFA port entry into the boiler. It also indicates that there is probably good coverage of the OFA air curtain across the boiler when the 2/3 dampers are open. Even though comparison of Figures 5-1 and 5-4 shows that at 2.5 percent O_2, there is lower CO without OFA than with full OFA, it is probably best from a CO standpoint to operate with full OFA to reduce the sensitivity. The reduction of the exponent expands the "Good Combustion Range" and improves the ability of the boiler to handle transients without exceeding short term CO limits.

Even though the general shape of the CO curve on Figures 5-1 through 5-4 matched GE-EER's model, the values of CO were considerably less than expected. GE-EER expected high CO because they did not expect the OFA to extend fully into the boiler. These results seem to indicate that it did and this is the reason for the disparity. It should also be noted that BPI achieved their contract guarantee of less than 100 PPM CO at 10 percent OFA flow and 2.5 percent O_2.

5.3 Good Combustion Range

From both a CO and NO_X standpoint, the testing indicated that the best mode of operation for Unit 1 is to have the OFA system with the 2/3 damper and maximum OFA flow (Figure 5-4). This mode expands out the "Good Combustion Range" to allow for fluctuations and changes in coal quality. The "Good Combustion Range" extends to the 250 PPM range because the CO lines starts to rise dramatically after that point. Operation with O2 levels below 2% would be unusual, but that flexibility is needed in the event of short term disturbances in coal quality or equipment failures necessitate low air levels to insure NOx compliance.

5.4 Ash LOI

Figure 5-8 shows the effect of OFA on fly ash LOI. This graph shows an approximate 25 percent increase in LOI with OFA. This is much less than predicted by the GE-EER model. This is also due to GE-EER not expecting full penetration of OFA into the boiler. No comparisons have been made yet comparing LOI with excess O_2 but previous testing has shown a stronger relationship than that shown by OFA percent alone. In any case, the amount of LOI is still acceptable and represents only small decreases in boiler efficiency. Obviously, the best way to lower LOI is to increase O_2 in the boiler. Operation with OFA will allow higher O_2 levels while still maintaining NO_X emissions.

5.5 VOC's

Even though no specific testing was done during this test on VOC's, it can be deduced from the reaction of CO and LOI that the installation of the OFA system will not result in a significant increase in VOC emissions. If CO is burned out in the OFA zone above the burner rows, then the low combustion temperature VOC's would also burn out leaving only trace amounts. This theory was confirmed with emission testing performed for Unit 3 modeling in April 2003 which indicated negligible impacts on VOC emissions with OFA. Specifically, tests for Aldehydes/Ketones showed emission rates below calculated values with OFA in-service. Because of the low combustion temperature of VOC's compared to that of CO and ash, there is no relationship between them.

O2% (control room) vs CO ppm (stack test) & NOx #/mbtu (stack CEM)
NO Overfire Air (5% cooling) OFA 1/3, 2/3, & inlet dampers closed

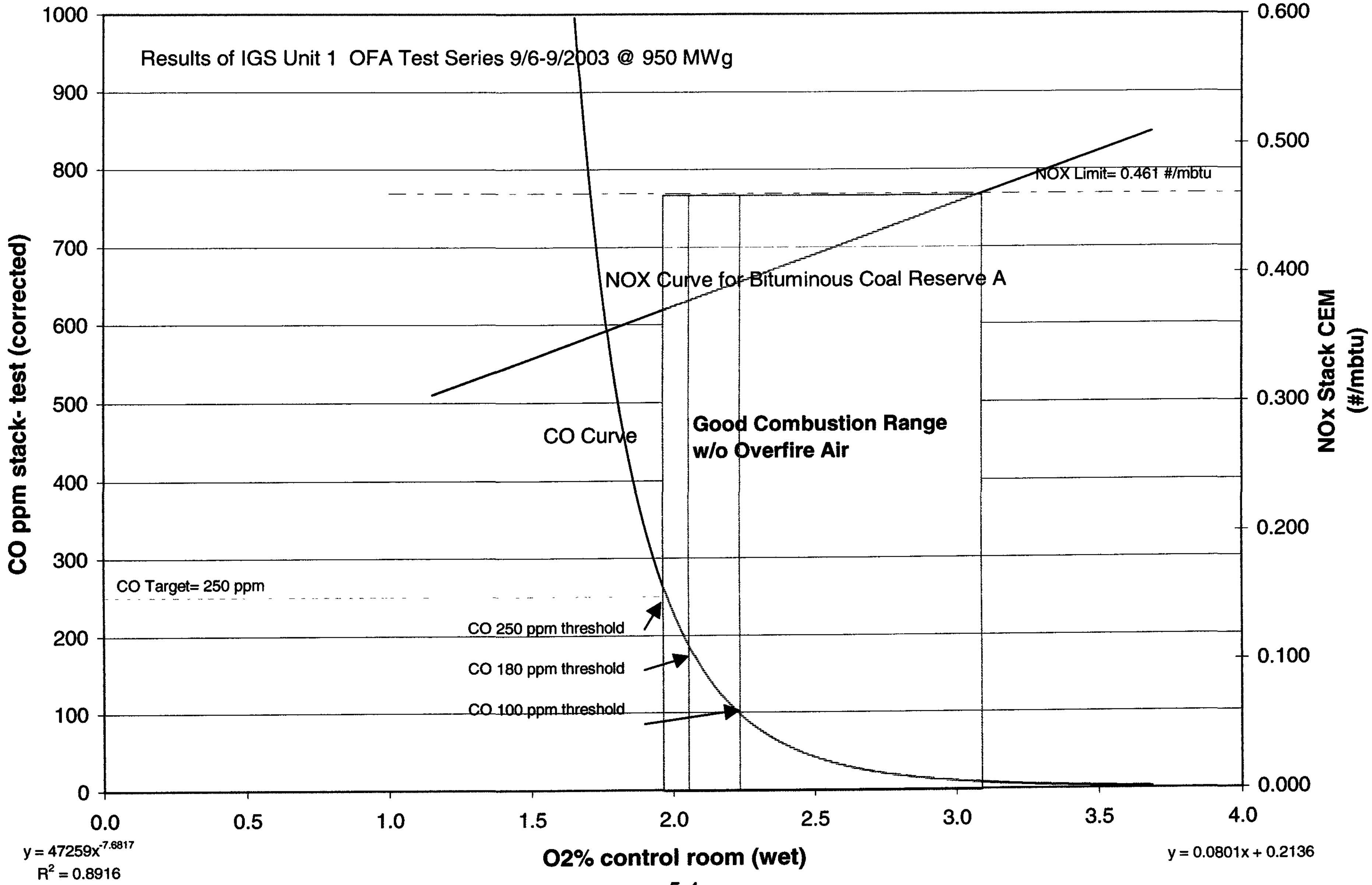


Figure 5-1

IP10_003341

O2% (control room) vs CO ppm (stack test) & NOx #/mbtu (stack CEM)
Overfire Air (10%) OFA 1/3 dampers- full open

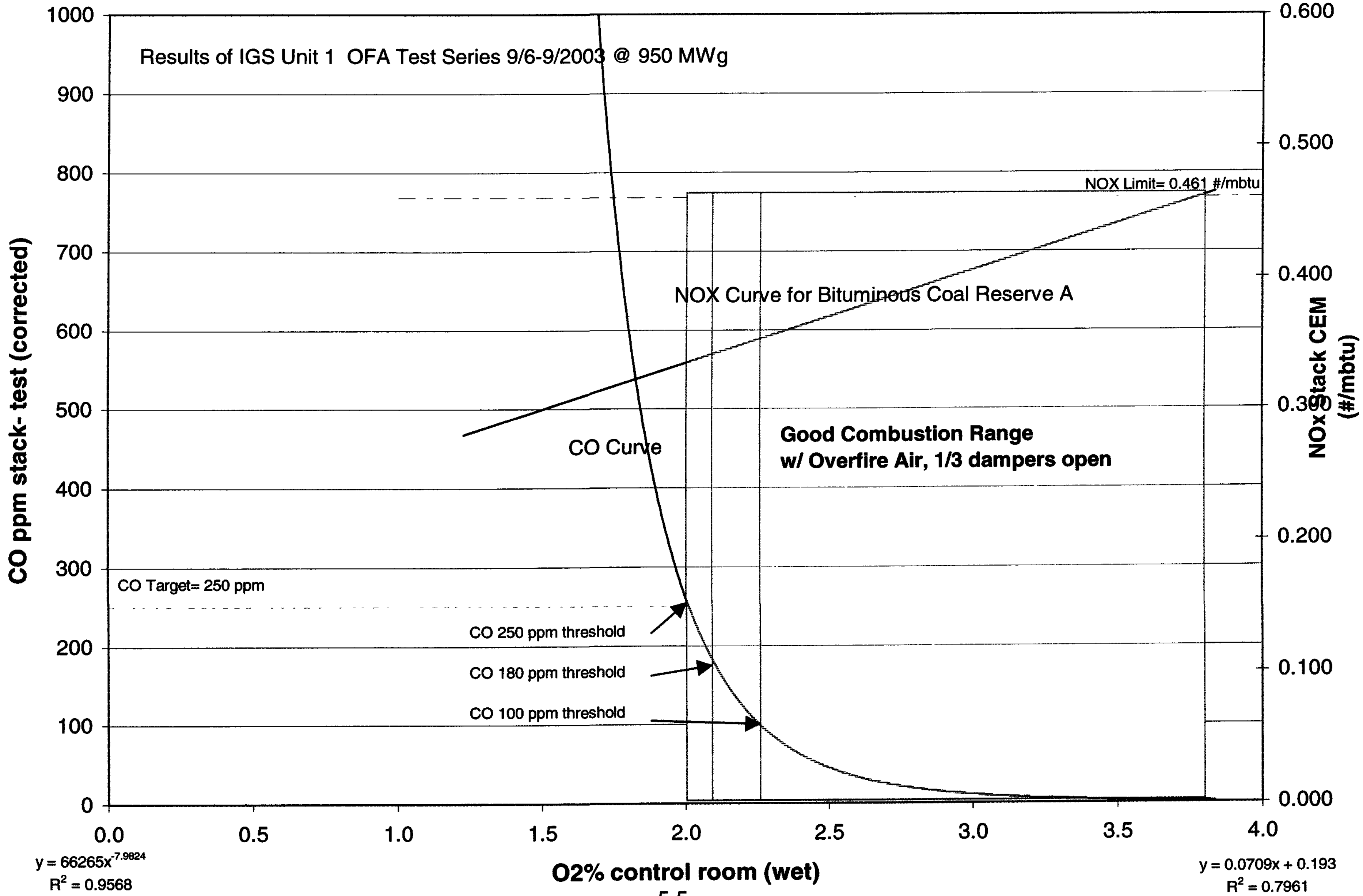
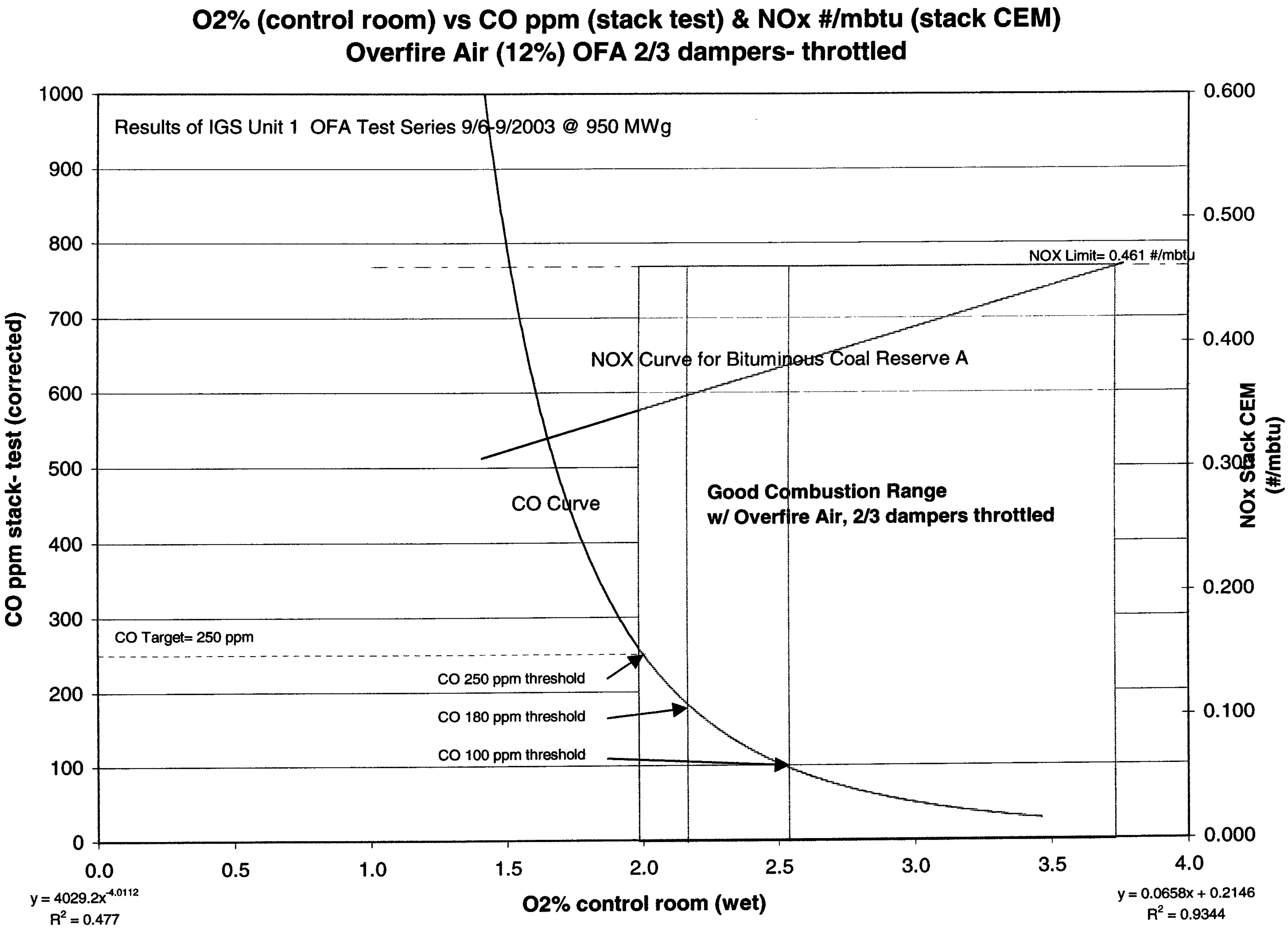


Figure 5-2

IP10_003342



O2% (control room) vs CO ppm (stack test) & NOx #/mbtu (stack CEM)
Overfire Air (12%) OFA 2/3 dampers- throttled
Results of IGS Unit 1 OFA Test Series 9/6-9/2003 @ 950 MWg
NOX Limit= 0.461 #/mbtu
NOX Curve for Bituminous Coal Reserve A
CO Curve
Good Combustion Range
w/ Overfire Air, 2/3 dampers throttled
CO Target= 250 ppm
CO 250 ppm threshold
CO 180 ppm threshold
CO 100 ppm threshold
CO ppm stack- test (corrected)
NOx Stack CEM (#/mbtu)
O2% control room (wet)
1000
900
800
700
600
500
400
300
200
100
0
0.600
0.500
0.400
0.300
0.200
0.100
0.000
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
y = 4029.2x^-4.0112
R^2 = 0.477
y = 0.0658x + 0.2146
R^2 = 0.9344

Figure 5-3

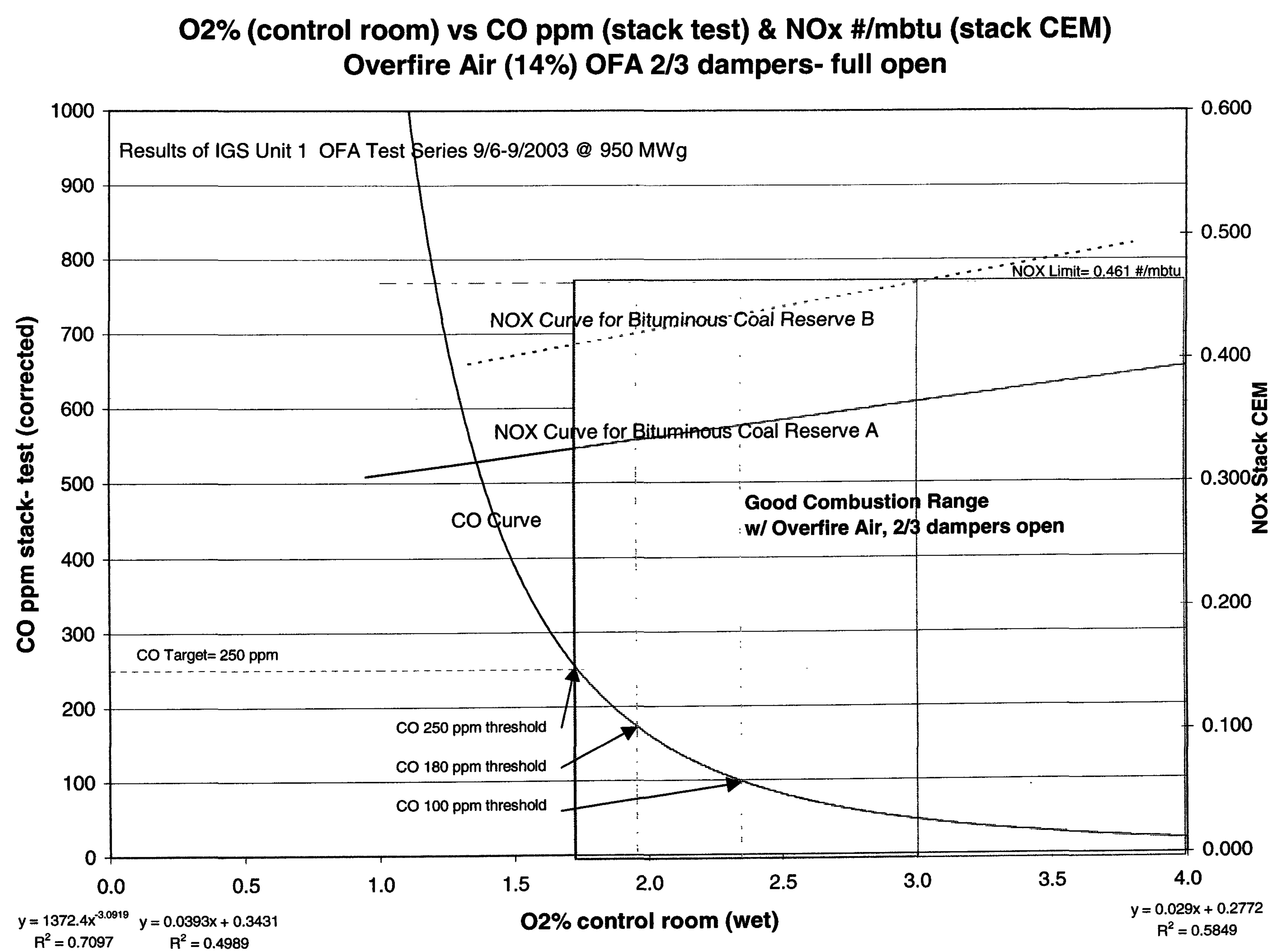


Figure 5-4

IP10_003344

NOX Emissions (#/mbtu) vs Overfire Air Flow (%)

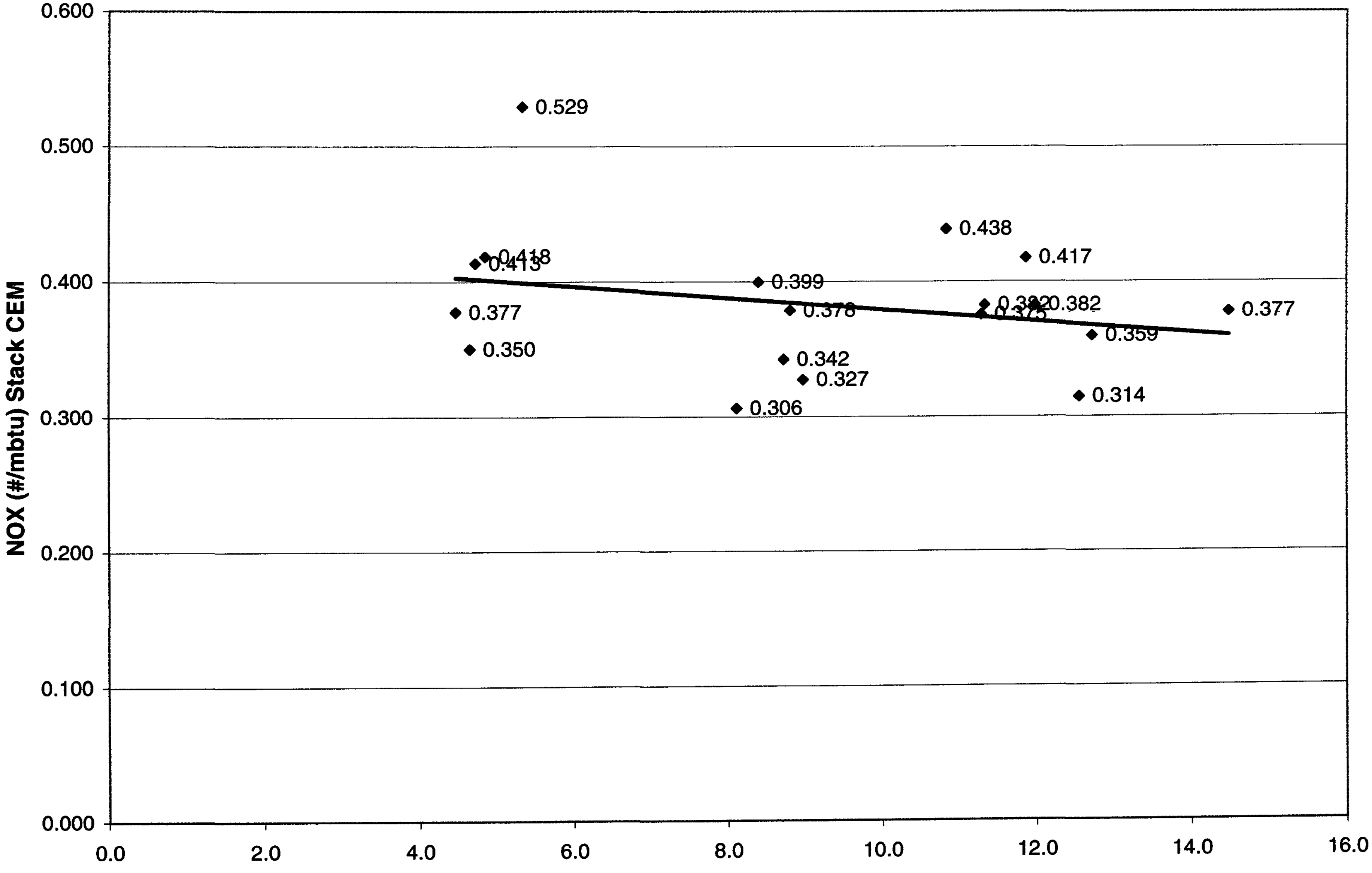


Figure 5-5

IP10_003345

NOX Emissions (#/mbtu) vs Overfire Air Flow (%) at varying O2 levels

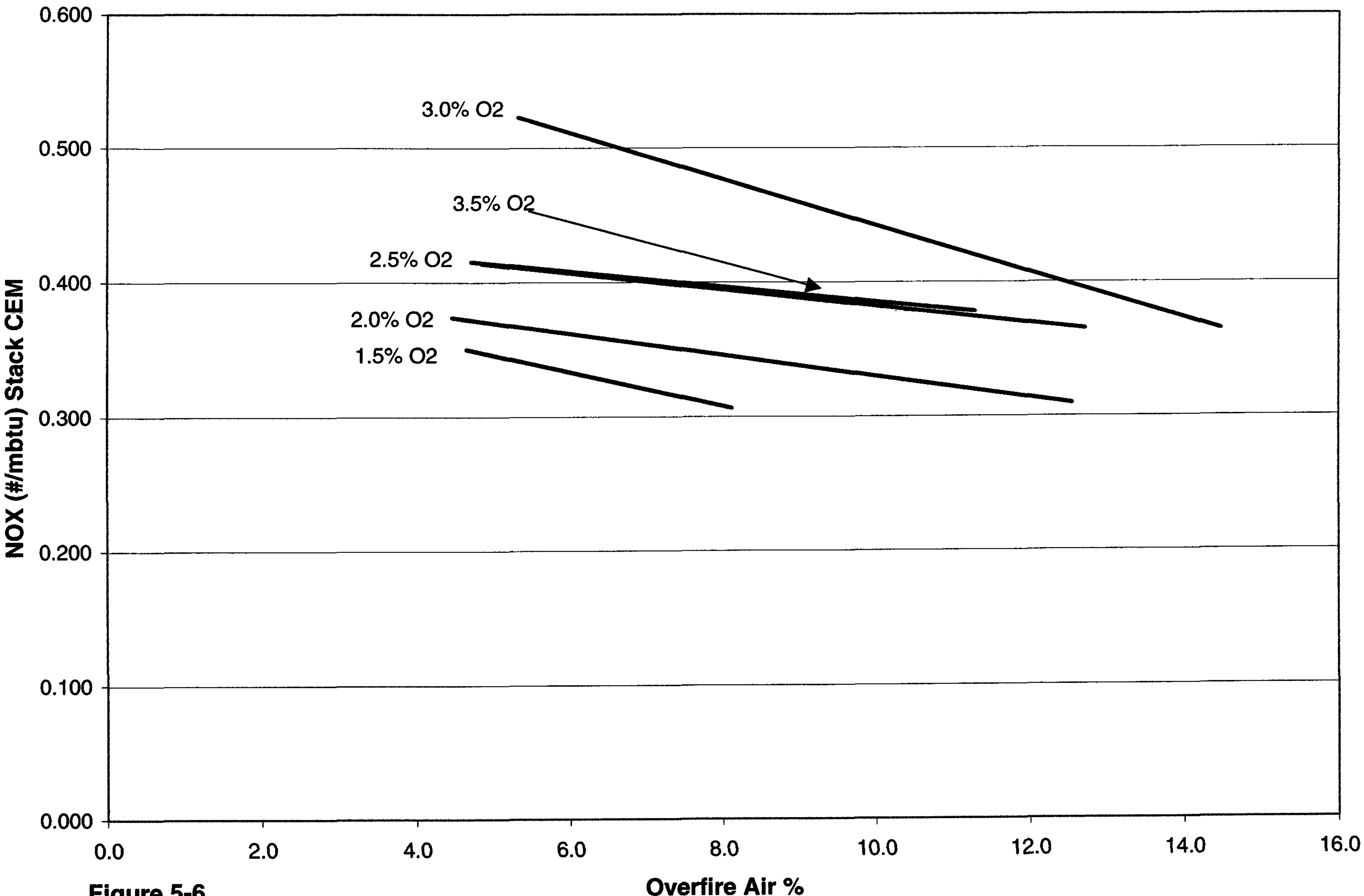


Figure 5-6

IP10_003346

Fly Ash LOI% (by IPSC) vs Overfire Air Flow (%)

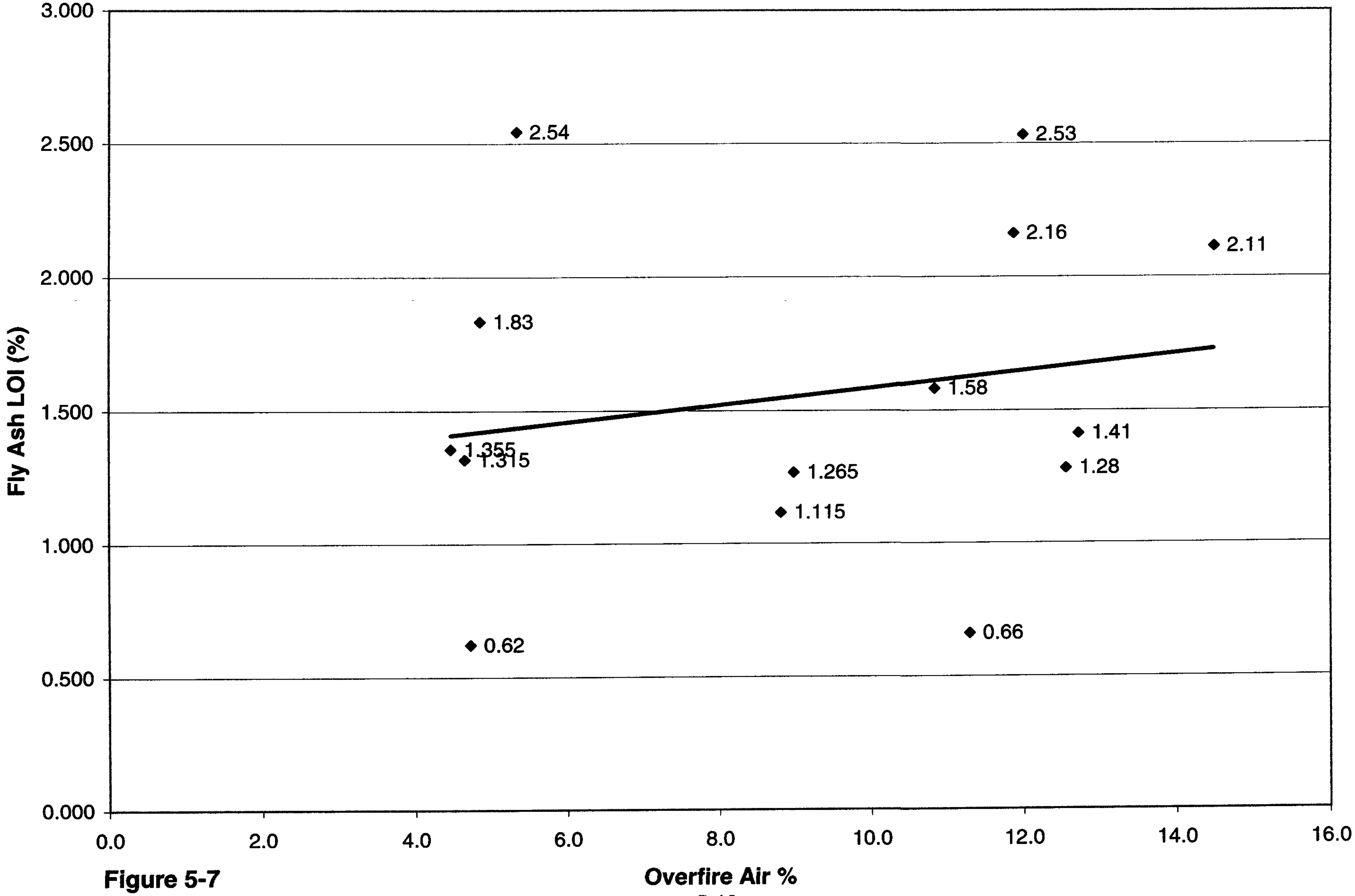


Figure 5-7

Section VI: Conclusions

Based on the results of the testing and analysis, the following conclusions can be made:

1. The OFA system works as intended and reduces the NO_X emissions from Unit 1 by approximately 14 percent when compared to operation without OFA and 2.5 percent excess O_2. The amount and level of reduction compare favorably with those predicted by both BPI and GE-EER.

2. The OFA system allows the unit to operate with higher excess air levels and still achieve the required NO_X emission rate.

3. Operation of the OFA system with the 2/3 dampers fully open results in less sensitivity to CO emissions than operation without OFA. OFA operation flattens out the curve for CO generation thus reducing the chance of large fluctuations in CO generation. This indicates that the OFA system has good coverage across the cross sectional area of the boiler at its admission point. The BPI contractual guarantee of CO generation of less than 100 PPM with 10 percent OFA and 2.5 percent excess oxygen was achieved.

4. CO generation is very sensitive to fuel and air flow balancing. Both the primary and secondary air flows should be checked for balance periodically to insure minimum CO generation.

5. While the OFA system controlled NO_X with relatively high excess air levels for this test, changes in coal quality may require operation at low levels of excess air even with the OFA system in service. Current and future emissions limits for CO should allow some room for operation at low levels of excess air so that the NO_X targets can be achieved.

6. The OFA system expands the "Good Combustion Range" by reducing NO_X removal with higher excess air and reduces CO generation with lower excess air.

7. Fly ash LOI's increase with increased percent of air to the OFA system and decreased percent of excess O_2. The most efficient combustion occurs with the highest allowable excess air level while still achieving required NO_X emission rates.

8. Since CO is being burned out in the OFA zone, VOC's are probably almost completely oxidized because of their lower ignition temperature compared to CO. Any VOC generation increases due to OFA should be negligible. Due the low ignition temperature of VOC's, there is no relationship between VOC increases and CO or LOI increases.

Abbreviations

Intermountain Generating Station	(IGS)
Over Fire Air	(OFA)
Intermountain Power Project	(IPP)
Intermountain Power Service Corporation	(IPSC)
Babcock & Wilcox	(B&W)
Advanced Burner Technology, Inc.	(ABT)
Babcock Power Services, Inc.	(BPI)
Dual Register Style Low NOx Burners	(DRB)

BABCOCK [illegible]SIG POWER®

OVERFIRE AIR S[illegible]EM EXPERIENCE LIST

PULVERIZED COAL FIRING

Contract Number	Company	Station Name	Location	Boiler Capacity PPH Steam	Turbo or Wall Fired	Overfire Air	Underfire Air	Boundary Air	Approx. SR_B	% Excess Air
72020	Carolina Power & Light	Roxboro Units 4A & 4B	Roxboro, NC	2,584,500	Wall	Yes	Yes	No	0.90	25
74030	South Miss. Electric PowerAuthority	R.D. Morrow Units 1 & 2	Hattiesburg, MS	1,575,000	Turbo	Yes	Yes	No	0.95	25
74041 77014 78001	Santee Cooper	Winyah Units 2, 3 & 4	Georgetown, SC	(3) 2,000,000	Turbo	Yes	No	No	1.0	17
74046	Delmarva Power & Light	Indian River Unit 4	Dagsboro, DE	2,943,000	Turbo	Yes	Yes	No	0.9	26
74058 75017	Salt River Project	Coronado Units	St. Johns, AZ	(2) 2,747,000	Turbo	Yes	No	No	1.0	20
75004 75015	Arizona Electric Power	Apache Units 2 & 3	Cochise, AZ	(2) 1,355,000	Turbo	Yes	No	No	0.9 1.0	26 18
75006 75016	Alabama Electric	Tombigbee Units 2 & 3	Jackson, AL	(2) 1,755,000	Turbo	Yes	No	No	1.0	20
75012	City of Gainesville	Deerhaven Unit 2	Hague, FL	1,768,000	Turbo	Yes	No	No	1.0	20
75034 75038	Cajun Electric Power	Big Cajun Units 1 & 2	New Roads, LA	(2) 4,300,000	Turbo	No	Yes	No	1.0	17
76012 76013	Hoosier Energy Rural Electric	Merom Units 1 & 2	Merom, IN	(2) 3,900,000	Turbo	Yes	No	No	1.0	20
82002	Fort Howard Corp.	Unit 4	Muskogee, OK	400,000	Turbo	Yes	Yes	No	0.87	28

BABCOCK[illegible]SIG POWER®
OVERFIRE AIR S[illegible]EM EXPERIENCE LIST
PULVERIZED COAL FIRING

Contract Number	Company	Station Name	Location	Boiler Capacity PPH Steam	Turbo or Wall Fired	Overfire Air	Underfire Air	Boundary Air	Approx. SR_B	% Excess Air
94527	Pub.Serv.Co of Indiana	Wabash River Unit 5	W.Terre Haute, IN	805,000	Wall	Yes	No	No	1.02	15
90521	City of Vineland	Howard Down Unit 10	Vineland, NJ	290,000	Wall	Yes	No	No	0.95	21
91573	Pub.Serv.Co of Indiana	Wabash River Unit 2	W. Terre Haute, IN	700,000	Wall	Yes	No	No	1.05	12
91575	Taiwan Power Co.	Linkou Unit 1	Tapei Taiwan	2,100,000	Wall	Yes	No	Yes	0.9	25
91006	Westmoreland Hadsen/ Ultrasystems	Roanoke Valley Project	Weldon, NC	1,250,000	Wall	Yes	No	Yes	0.92	23
91007	Tennessee Eastman Co.	Boiler No.31	Kingsport, Tennessee	600,000	Wall	Yes	No	Yes	0.90	25
92526	Pub. Serv. Co. of Indiana	Gallagher Unit 2	New Albany, Indiana	1,000,000	Wall	Yes	No	No	1.0	17
92546	Potomac Electric Power Co.	Chalk Point Units 1 & 2	Aquasco, Maryland	2,500,000	Wall	Yes	No	No	1.0	17
93513	Pennsylvania Power & Light	Martins Creek Unit 1	Martins Creek, PA	1,340,000	Wall	Yes	No	No	1.11	8
93514	Pennsylvania Power & Light	Martins Creek Unit 2	Martins Creek, PA	1,340,000	Wall	Yes	No	No	1.09	9
93515	Pennsylvania Power & Light	Sunbury Unit 3	Shamokin Dam, PA	880,000	Wall	Yes	No	No	1.08	10
93516	Pennsylvania Power & Light	Sunbury Unit 4	Shamokin Dam, PA	1,100,000	Wall	Yes	No	No	0.95	21
93528	New England Power	Salem Harbor Unit 3	Salem, MA	1,000,000	Wall	Yes	No	No	0.95	21
93538	Pub. Serv. Co. of Indiana	Wabash River Units 3 & 4	W. Terre Haute, IN	700,000	Wall	Yes	No	No	1.05	12
35002	Mitsui for Thai-Petrochemical	-	Rayong, Thailand	560,000	Wall	Yes	No	Yes	—	—
93004	Ultrasystems	Roanoke Valley Project	Weldon, NC	410,000	Wall	Yes	No	Yes	0.90	25

BABCOCK [illegible]SIG POWER
OVERFIRE AIR S[illegible]EM EXPERIENCE LIST
PULVERIZED COAL FIRING

Contract Number	Company	Station Name	Location	Boiler Capacity PPH Steam	Turbo or Wall Fired	Overfire Air	Underfire Air	Boundary Air	Approx. SR_B	% Excess Air
93546	Pub.Serv Co. of Indiana	Gallagher Units 1, 3 & 4	New Albany, Indiana	1,000,000	Wall	Yes	No	No	0.95	21
93560	City Utilities of Springfield	James River Unit 5	Springfield, MO	725,000	Wall	Yes	No	No	0.95	21
93570	Northeast Utilities	Mt. Tom Station	Holyoke, MA	950,000	Wall	Yes	No	No	1.10	8
94513	Delmarva Power & Light	Indian River Unit 3	Dagsboro, DE	1,061,000	Wall	Yes	No	Yes	0.92	23
94536	City Utilities of Springfield	James River Units 3 & 4	Springfield, MO	400,000 450,000	Wall	Yes	No	No	1.05 1.0	12 17
94548	Iowa Electric Light & Power Co.	Prairie Creek Unit 4	Cedar Rapids, IA	950,000	Wall	Yes	No	Yes	0.95	21
94554	Pennsylvania Electric Co.	Homer City Unit 3	Homer City, PA	4,845,000	Wall	Yes	No	Yes	0.96	20
94555	General Foods Corp.	Cogeneration Project	Dover, DE	190,000	Wall	Yes	No	No	—	—
95509	Northeast Utilities	Mt. Tom Station	Holyoke, MA	1,070,000	Wall	Yes	No	No	—	—
95518	Norton Co.	Norton	Worcester, MA	150,000	Wall	Yes	No	No	1.03	15
95519	P.H. Glatfelter	Spring Grove Unit #1	Spring Grove, PA	200,000	Wall	Yes	No	No	1.20	-0-
71904	for Mitsui	Hiang Seng Fiber Container Co.	Bangkok, Thailand	1,188,000	Wall	Yes	No	No	0.95	21
100007	DOE LEBS Project	Turris Coal Mine POC Facility	Elkhart, Illinois	650,000	U-Fired	Yes	Yes	No	0.85	30
100085	Wisconsin Electric Power Company	Presque Isle Unit 5	Marquette, MI	615,000	Wall	Yes	No	No	0.95	21
100091	Detroit Edison	St. Clair Unit 3	St. Clair, Michigan	1,070,000	Wall	Yes	No	No	0.90	25
100131	Detroit Edison	Belle River Units 1 & 2	St. Clair, Michigan	4,550,000	Wall	Yes	No	Yes	0.90	25

ABT Low No_x Burner - Experience List

<u>Deseret, Bonanza Unit 1:</u> A 440 MW Foster Wheeler boiler, firing western bituminous coal similar to the worst Intermountain coal, was retrofitted in May 1997 with 20 Opti-Flow low NO_x burners. NO_x emissions before the retrofit, with the original Foster Wheeler low NO_x burners, were typically in the 0.55 to 0.6 range. After the retrofit, with the ABT low NO_x fuel injectors and dual register modifications, NO_x is approximately 0.35. In 2001, three of the five mills were replaced with larger units and the new mill's burners were upgraded to handle the higher capacity. The boiler now produces 500 MW with no increase in NO_x or detrimental impacts to boiler performance. Burner coking and fires have been eliminated, as have burner eyebrows and furnace slag.

Deseret Contact: Dan Howell 435-781-5718

<u>AEP/SWEPCO, Welsh #1:</u> A 560 MW B&W boiler with 42 burners (NO_x with OEM dual register low NO_x burners was ~0.38). Unit was retrofitted with ABT Opti-Flow Mark I burners in the fall of 1999; initially no OFA ports were installed. Operating with one top burner deck out of service, NO_x was typically in the 0.20 to 0.22 range.

In the fall of 2001, ABT's OFA system was installed at Welsh #1. With the OFA ports open, NO_x has been reduced to the 0.16 – 0.17 range with all mills in service. It is apparent that significant coal line imbalances exist at Welsh #1; these imbalances limit the degree of NO_x reduction that can be achieved, since they result in high CO emissions. Although the unit was designed for operation with 19% excess air, it must currently operate with approximately 25% excess air in order to control CO. Minimizing these coal line imbalances will allow operation at near design excess O_2 or below and reduce the NO_x to the 0.15 level.

<u>AEP/SWEPCO, Pirkey #1:</u> A 700 MW B&W boiler firing Texas lignite (NO_x with OEM dual register low NO_x burners was ~ 0.36 to 0.38). The unit was completely retrofitted with 56 ABT Opti-Flow Mark II Low NO_x burners and OFA system in the fall of 2001. NO_x emissions, with the OFA ports closed, have been lowered to approximately 0.22. Operation of the OFA system has been very successful in that the boiler can operate continuously at full load with NO_x emissions of ~ 0.15 $lb/10^6$ Btu with one mill out of service (normal operation).

AEP Contact: Kent Randall 318-673-3813 Welsh & Pirkey Plants

<u>Kentucky Utilities, Ghent #3 and #4:</u> Two 540 MW FW boilers firing Kentucky bituminous coal. NO_x emissions of 0.55 to 0.7 without OFA and about 0.45 with OFA ports open were attained with the OEM low NO_x burners and OFA system. ABT replaced all 24 fuel injectors, with the Opti-Flow Mark I design, upgraded the FW dual registers and supplied a new OFA system to each boiler. Unit #3 was converted in the fall of 1998 and Unit #4 in the fall of 1999. NO_x was reduced to about 0.40 while firing Eastern bituminous coal and 0.23 for PRB coal, with OFA ports closed; and to 0.3 and 0.18 respectively with OFA ports open. Currently, NOx is about 0.3 firing a 50/50 blend of E. bituminous and PRB with OFA ports closed.

The walls of these boilers are coated with refractory to maintain furnace temperatures and to attain design steam temperatures (low steam temperatures resulted from an OEM boiler design problem). Prior to the retrofit, there were frequent heavy slag falls from the walls; however not a single slag fall has been observed following the retrofit.

Ghent Contact: Steve Nix 502-347-4152

__Allegheny Energy, Harrison #1, 2 and 3:__ Three 660 MW FW boilers that are of pre-NSPS design with very hot, tight furnaces firing a highly slagging, eastern bituminous coal. All units were upgraded by replacing the fuel injector with the ABT design, while maintaining the existing FW dual registers. NO_x emissions have been reduced from the 0.55 to 0.6 range to below 0.45 without overfire air. The furnaces are clean with no evidence of any operating or performance problems, due to the new low NO_x burners. Unburned carbon is in the same range as before the retrofit.

Harrison Contact: Dean Hedrick 304-584-2350

__Tyrone Unit#3/ Green River Unit #3:__ These are 70 MW B&W boilers each originally with eight turbulent burners firing Eastern bituminous coal. Tyrone was started up in fall 2001 and Green River in spring 2002.
NO_x has been reduced from about 0.8 to below 0.35 lb/10^6 Btu without OFA. There was no increase in UBC and no deterioration in boiler performance or efficiency.

Tyrone Contact: Tom Moore 859-879-3501
Geen River Contact: Tom Troost 270-757-3113

__JEA St. John Unit #1:__ A 660 MW Foster Wheeler boiler that fires a blend containing 20% petroleum coke and 80% bituminous coal with 28 burners; more petroleum coke is fired in this boiler than any other pulverized coal boiler in the U.S. In addition, Colombian coal is fired in this blend, which makes it an even more difficult fuel since this coal is commonly known to be difficult to burn.

In early 2003, St. Johns Unit 1 was completely retrofitted with 28 Opti-Flow™ LNB's and similar windbox/secondary air modifications. Preliminary burner tuning has shown that NO_x has been reduced by over 20% for Unit 1; further reduction in NO_x is anticipated once additional burner tuning is completed.

Excellent flame stability has also been attained with the retrofit of Opti-Flow™ burners for Unit 1. In fact, the petroleum coke blend can now be fired in the lower rows of burners without flame stability problems. Excellent flame stability is also maintained as load is reduced from 670 MW to 380 MW, with only one mill out of service (normal operating practice with these boilers). Prior to the retrofit of Opti-Flow™ burners, this turndown could not be achieved with only one mill out of service. To date, ABT is the first to demonstrate the ability to cofire petroleum coke in a wall-fired boiler with an advanced low NO_x burner that maintains such excellent flame stability and NO_x reduction.

St. Johns Contact: Bob Branning 904-665-8806

ISG Unit 1 8/25/2003
Coal Burner Line Balancing- Dirty Air Flow Tests

Final Velocity Readings

Rear Wall Coal Pipe	6	5	4	3	2	1	Pulv average
D	5829	5985	5979	5990	5869	5734	5898
H	5175	5028	5047	5181	5207	5290	5154
C	6074	6145	5939	6205	6262	6188	6136
G	5490	5304	5250	5187	5277	5487	5333

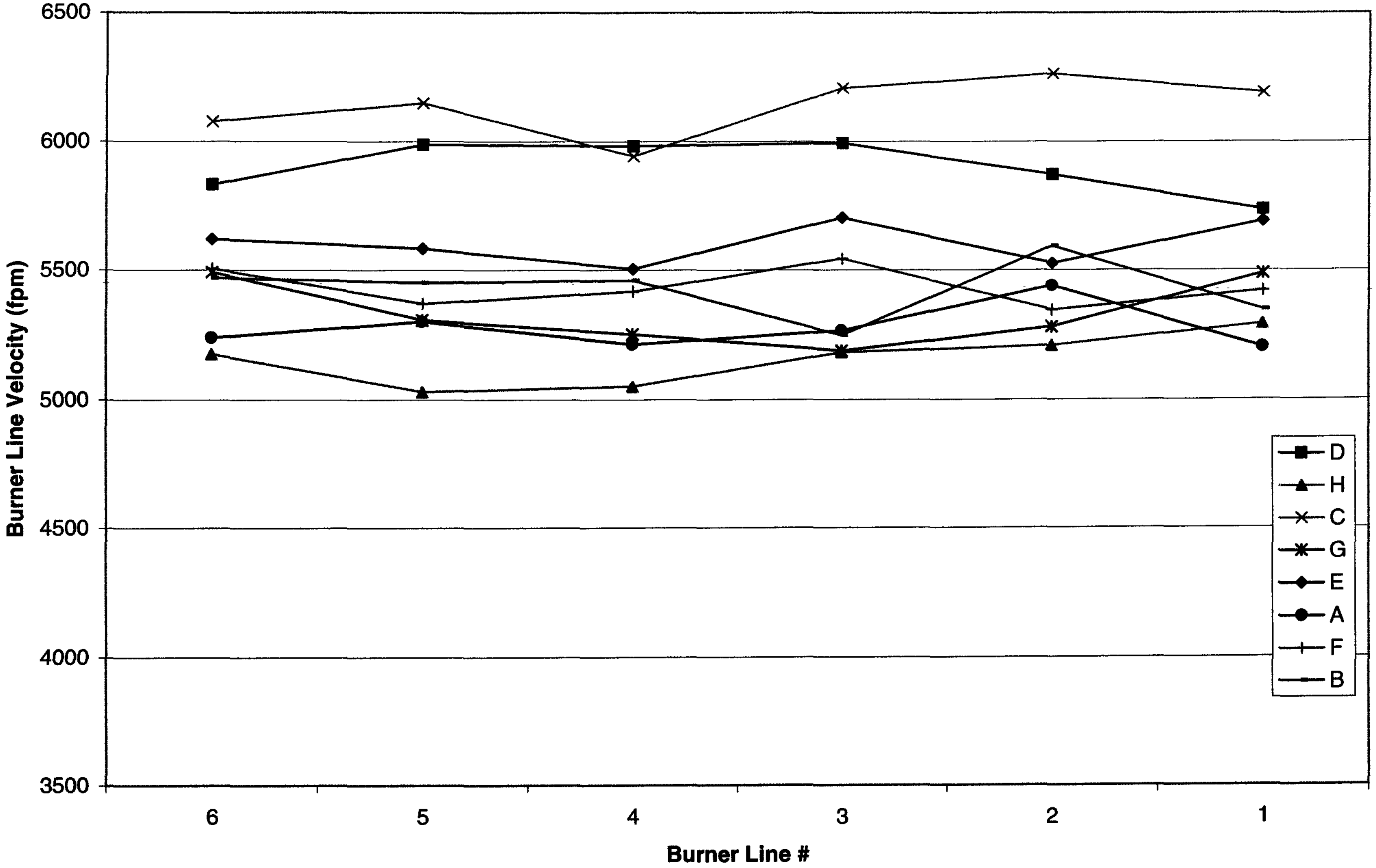
Front Wall Coal Pipe	6	5	4	3	2	1	
E	5619	5581	5502	5703	5525	5690	5603
A	5237	5299	5211	5263	5437	5201	5275
F	5504	5368	5414	5543	5344	5419	5432
B	5467	5449	5458	5245	5591	5345	5426

Starting Velocity Readings

Rear Wall Coal Pipe	6	5	4	3	2	1	Pulv average
D	5294	6070	5295	5615	5410	5440	5520
H	5174	4673	5072	5981	6016	5899	5469
C	5792	5507	5299	4649	4871	5148	5211
G	5478	4904	5147	5153	5046	5011	5123

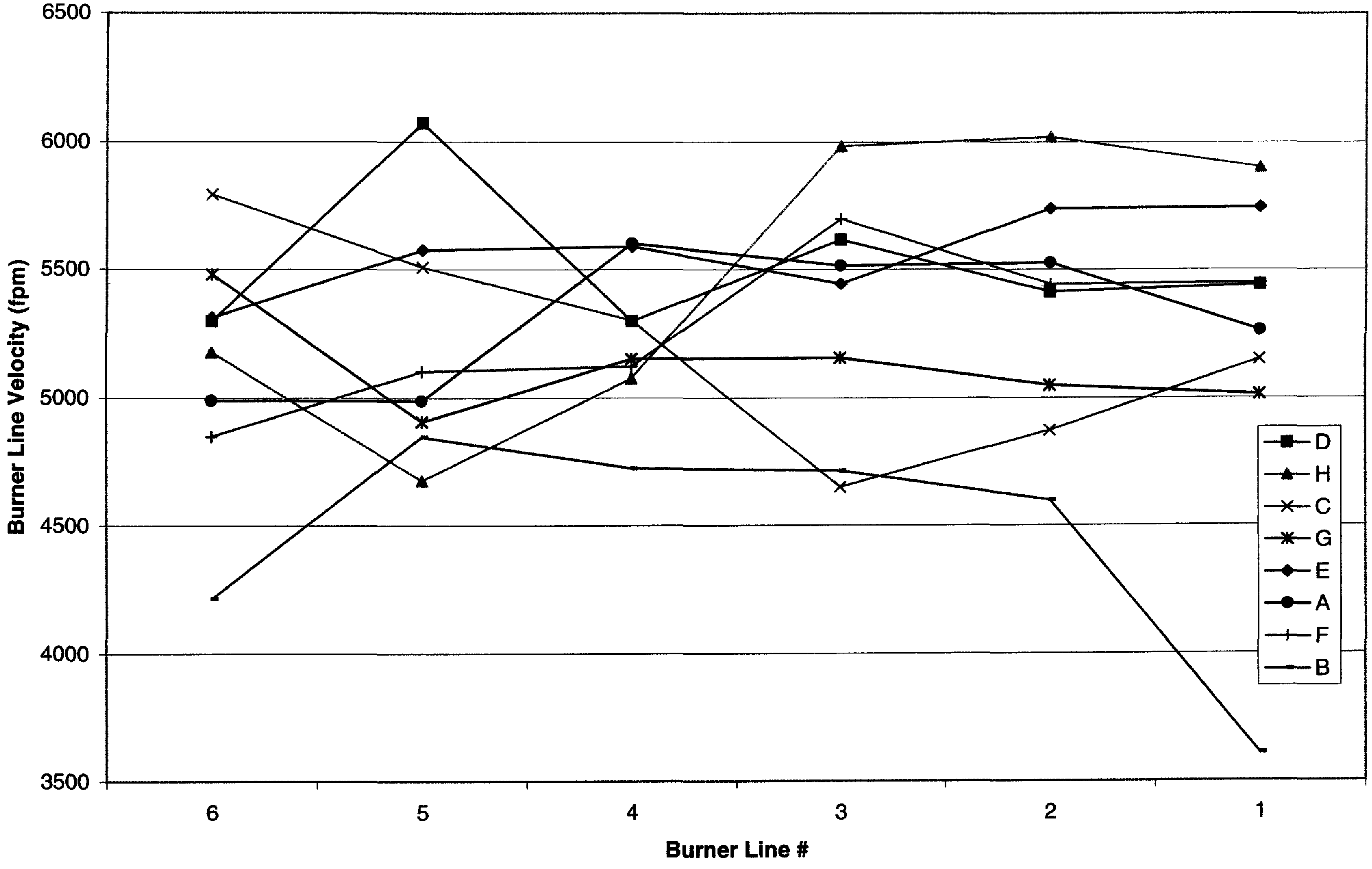
Front Wall Coal Pipe	6	5	4	3	2	1	
E	5308	5573	5587	5440	5736	5742	5565
A	4987	4985	5600	5512	5525	5261	5312
F	4846	5099	5120	5695	5441	5446	5274
B	4214	4845	4722	4711	4597	3610	4450

COAL BURNER LINE BALANCING- Dirty Air Flow Testing
8/25/2003, After Balancing



IP10_003357

COAL BURNER LINE BALANCING- Dirty Air Flow Testing
8/25/2003, Before Balancing



IP10_0033358

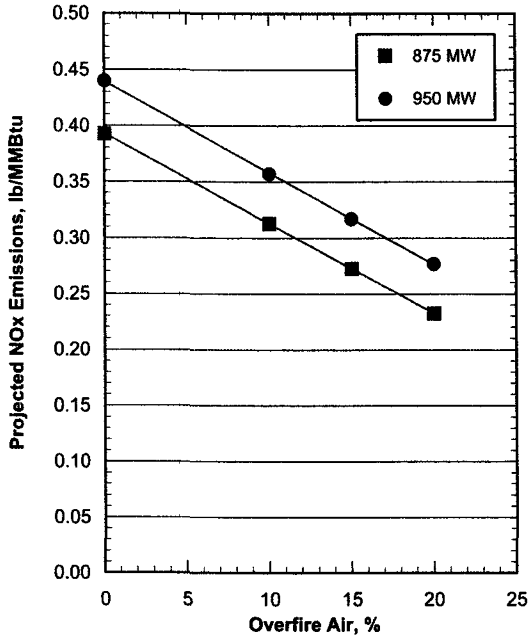


Figure 4-5. Predicted Fuel A NO_X emissions for OFA at different loads.

The projected impacts of the different fuels fired on NO_X emissions with and without overfire air are shown in Figure 4-6. In comparison to Fuel A, the combustion of Fuels B-E is expected to result in higher NO_X emissions due to the differences in fuels characteristics. Therefore, it is expected that higher levels of overfire air will be required when firing these fuels in order to minimize their impact on the unit NO_X emissions.

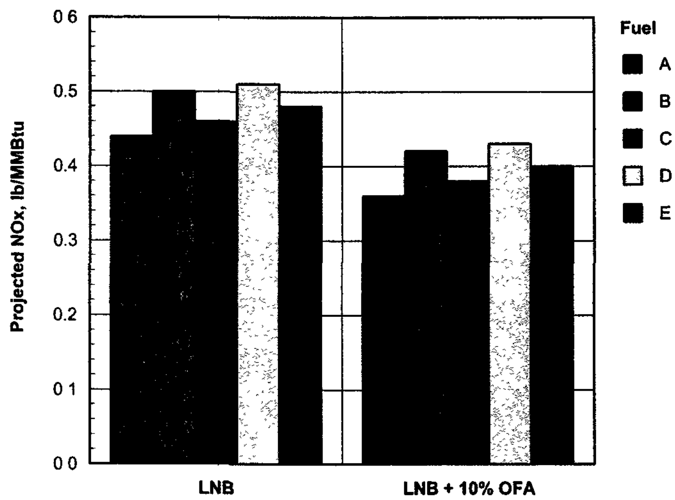


Figure 4-6. Predicted NO_X emissions for different fuels at 950 MW load conditions.

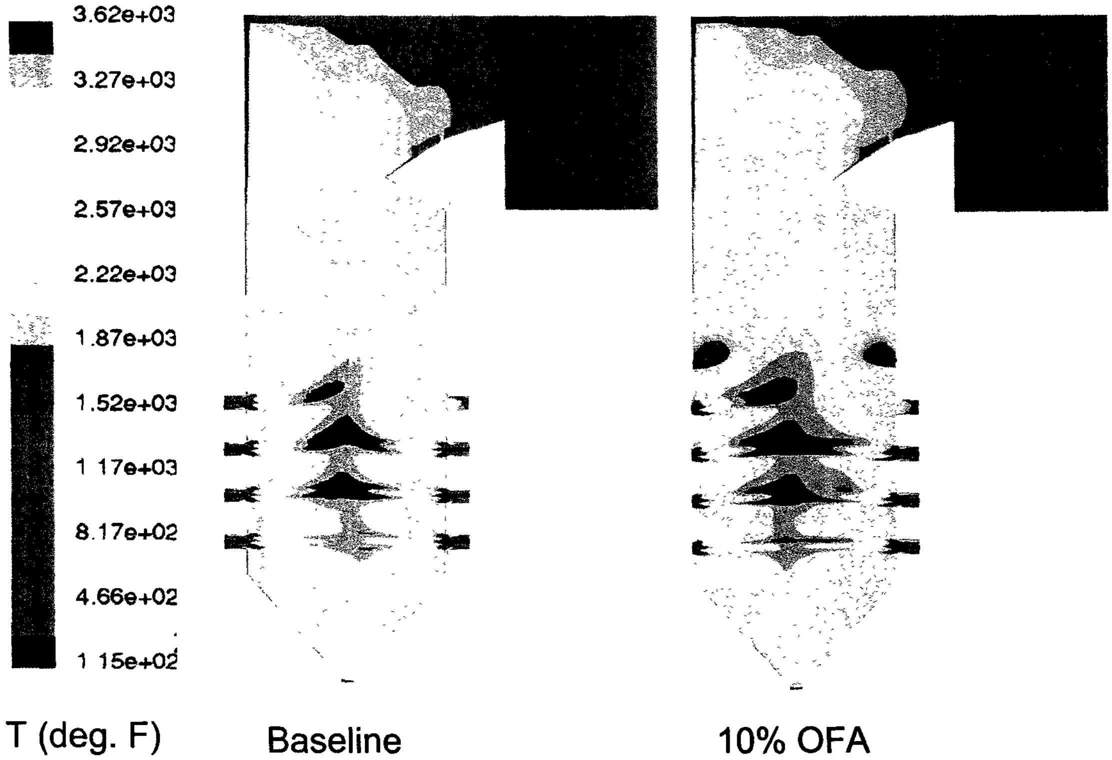


Figure 3-2. Comparison of side-view temperature contours.

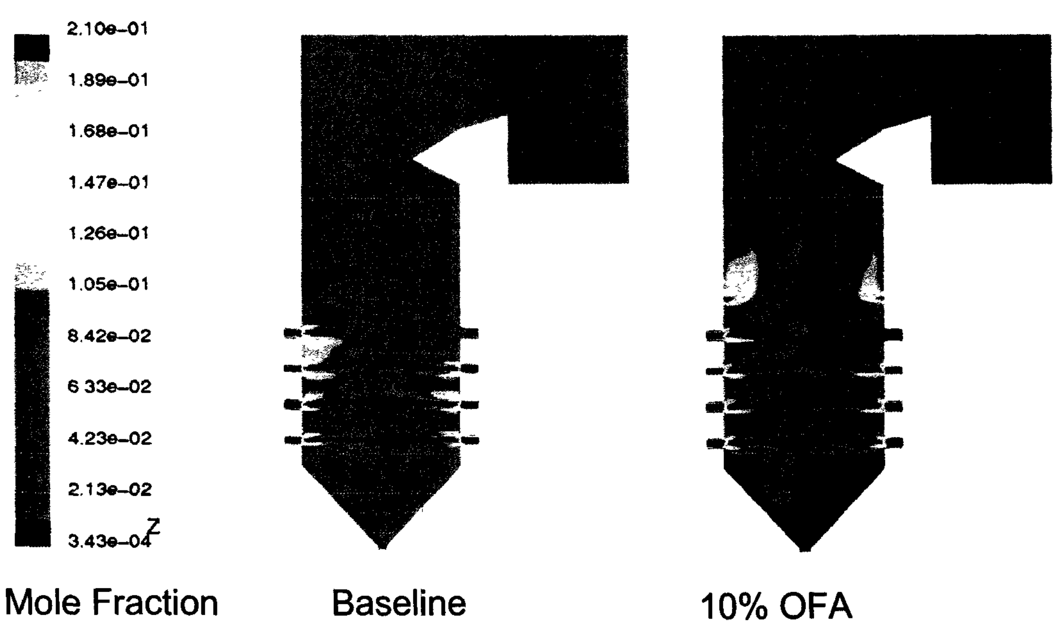


Figure 3-3. Comparison of side-view O_2 mole fraction contours.

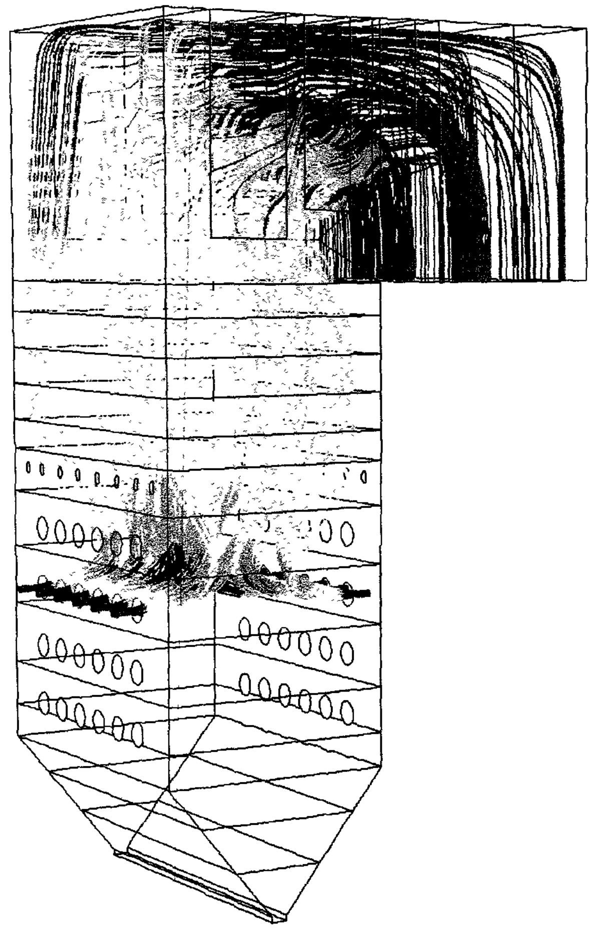


Figure 3-7. Burner path lines for baseline conditions.

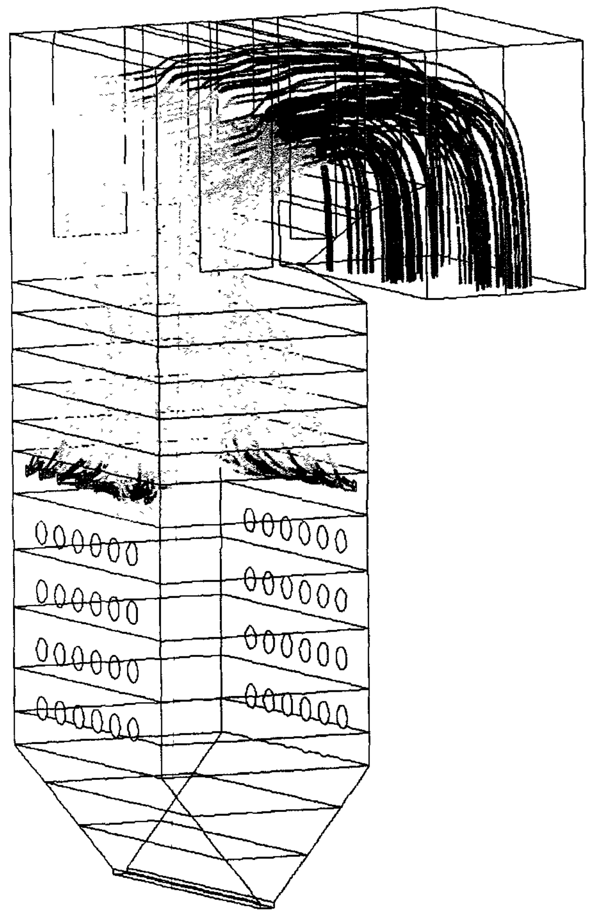


Figure 3-8. Air path lines at 10 percent OFA.

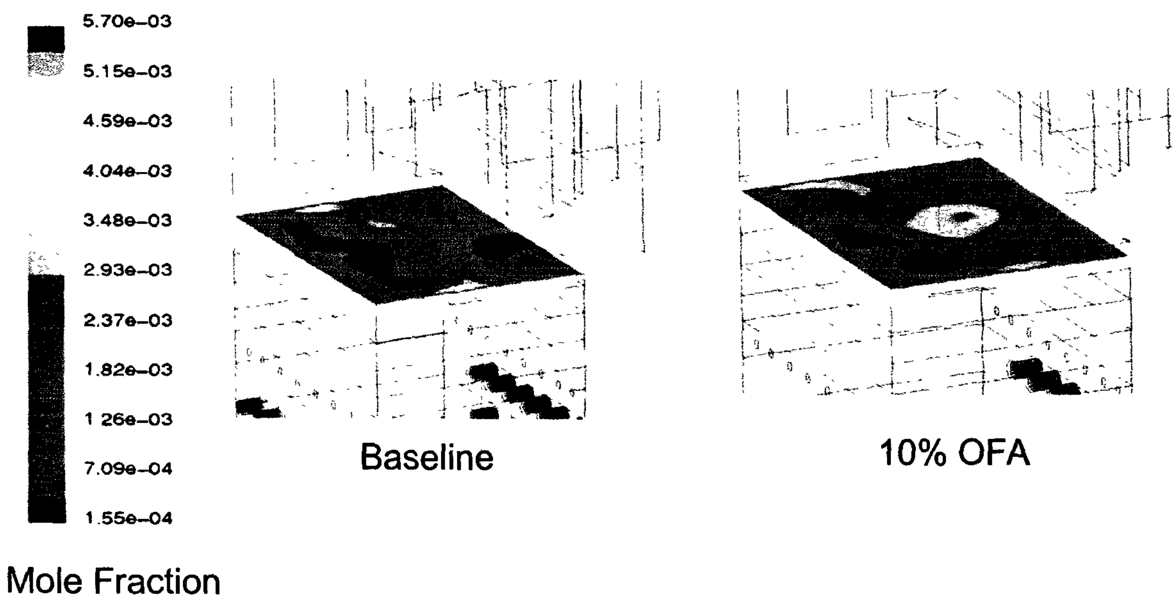


Figure 3-9. Comparison of CO mole fraction contours at the furnace nose plane.

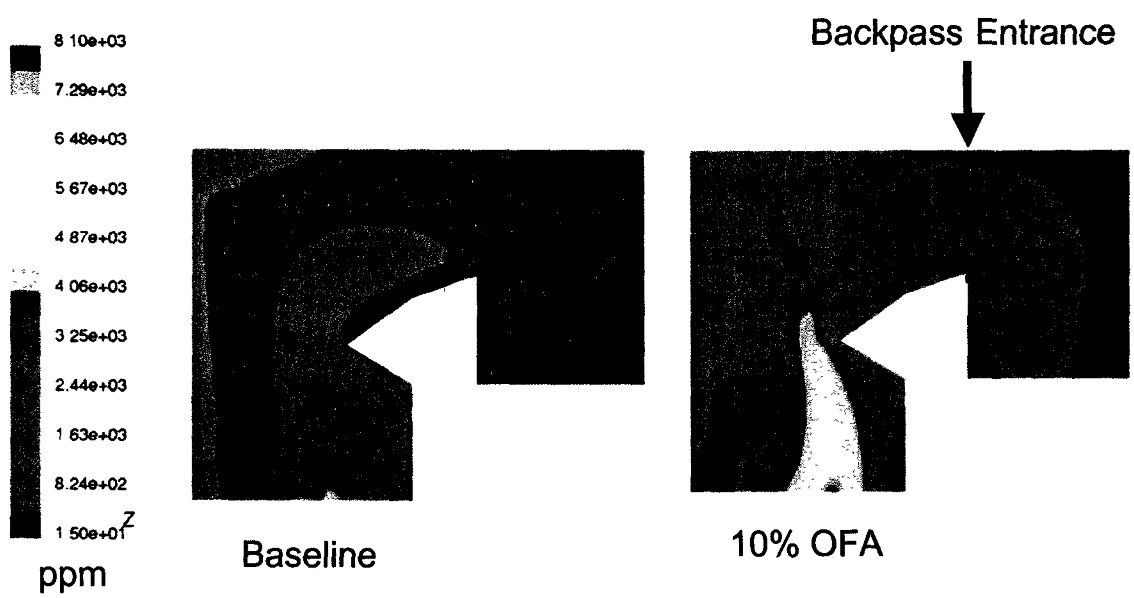


Figure 3-10. Comparison of side-view CO concentration (ppm) above the OFA injection plane

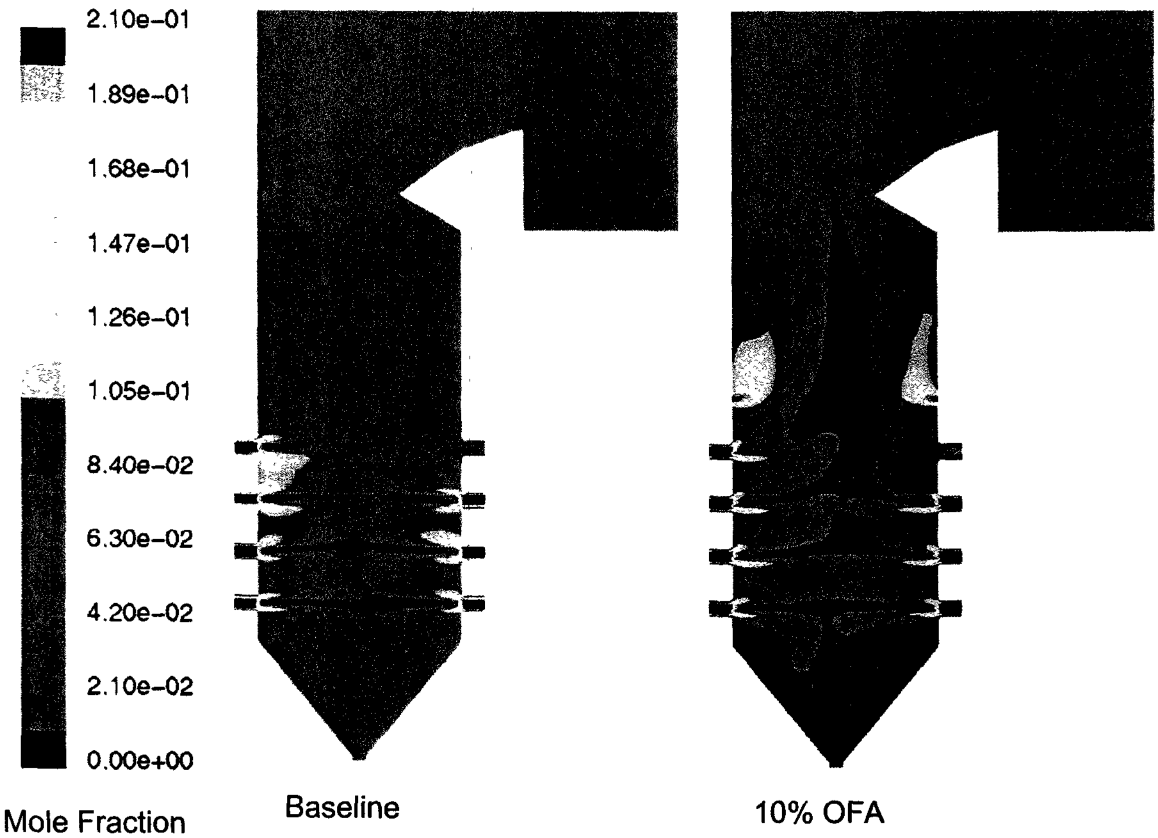
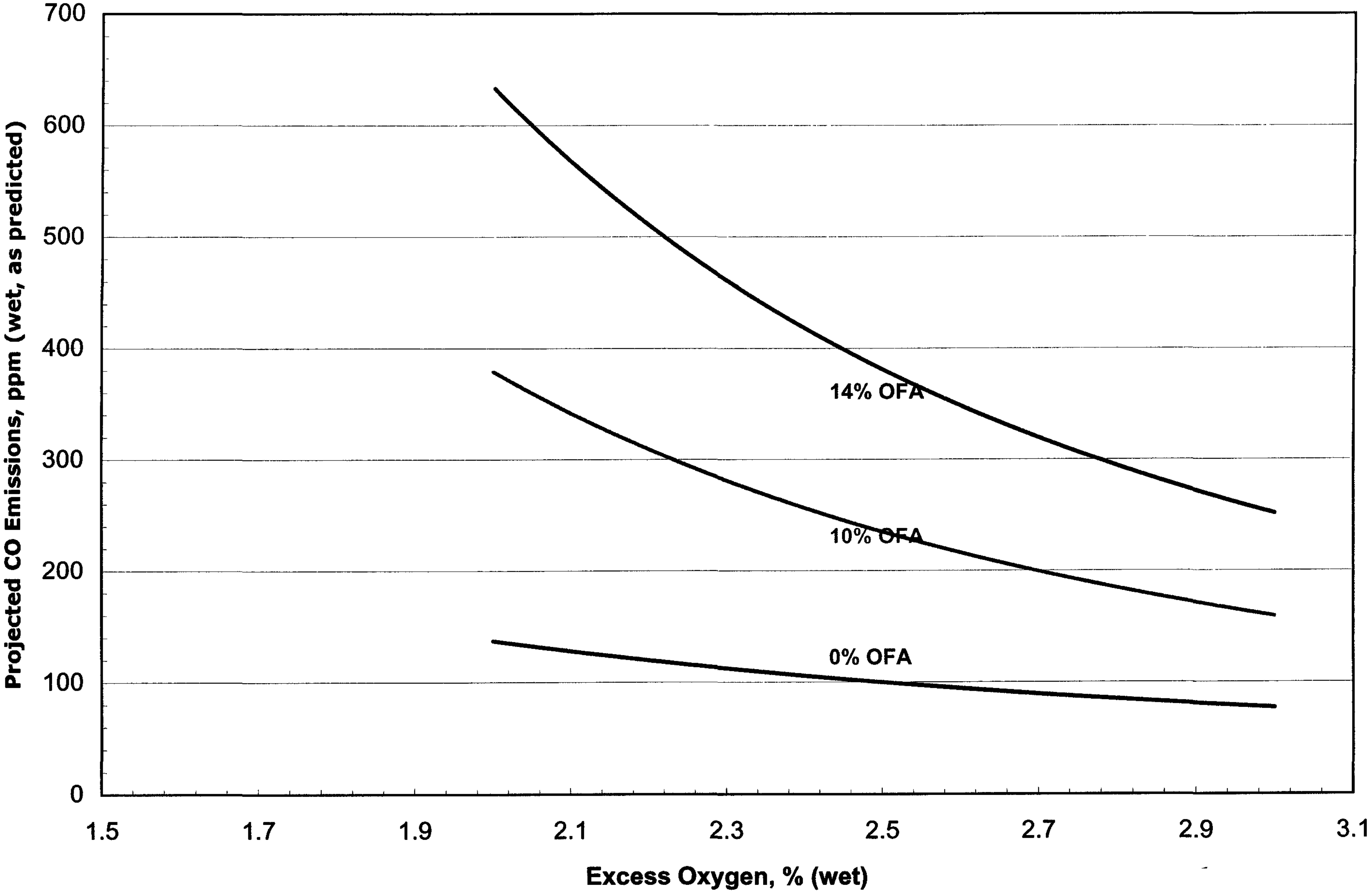
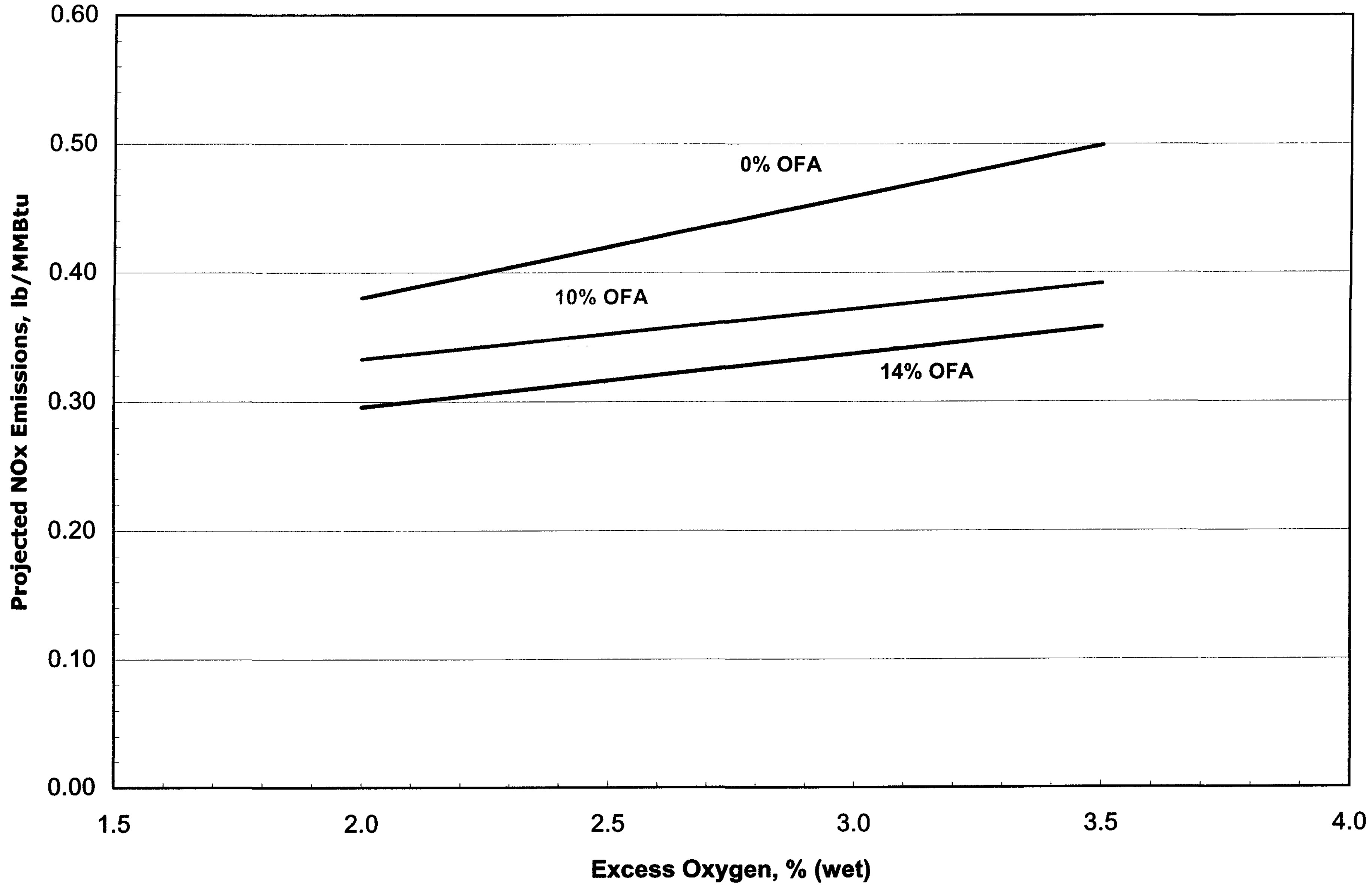


Figure 3-15. Comparison of side-view O_2 mole fraction contours with additional platen surface area.


700
600
500
400
300
200
100
0
Projected CO Emissions, ppm (wet, as predicted)
1.5
1.7
1.9
2.1
2.3
2.5
2.7
2.9
3.1
Excess Oxygen, % (wet)
14% OFA
10% OFA
0% OFA



0.60
0.50
0.40
0.30
0.20
0.10
0.00
Projected NOx Emissions, lb/MMBtu
0% OFA
10% OFA
14% OFA
1.5
2.0
2.5
3.0
3.5
4.0
Excess Oxygen, % (wet)

Boiler Performance Test Plan for Burners & Over Fire Air System 9/03/03 r0

IGS Unit 1 POST-Outage Testing

Testing Objectives- The primary objective of the proposed testing is to collect NOX and CO emissions data (along with all operational data) from the burner and overfire air system. The following Testing Series of Boiler-Burner/ OFA Tests are being requested following the modifications and tuning which have been made to IGS Unit 1 burners and overfire air system. The Unit 1 Major Outage (4 week) modifications consisted of installing an overfire air system above the burners and extending the superheater platen section.

The tuning consisted of 1) Burner Line (Coal) Balancing which consisted of installing dynamic coal restrictors on all 8 sets of 6 burner lines and conducting dirty air flow tests and balancing test series to reduce side to side coal imbalances, 2) Air Flow Balancing through the Burners. This consisted of balancing inner and outer air flows through the dual register burner. One of the objectives was to increase windbox duct pressure by throttling flows thru the inner four burner's outer registers. The economizer duct Flue Gas Test Grid was used to provide profiling capability to focus in on "bad actor" burners. Note, we have conducted all of the above testing and balancing in the past, but to achieve the next level of emissions reduction, we have to take balancing and tuning to the next level.

The **purpose** of the POST-outage testing is as follows: The **State of Utah Air Quality** has requested IPSC to demonstrate and document operating conditions after the Overfire Air System has been installed. POST-outage testing is being conducted based on concerns from the State that operating with the overfire air system may result in an exceptional increase in CO emission levels.

The Boiler Testing will be at POST-Outage Test Conditions (i.e.- new uprated Load of 950 MWgross), Coal Supply- must be consistent- NO Westridge and Dugout coal blends (best if SUFCO is straight), O2% & Overfire Air% varies to give us CO, NOx emissions (see Boiler Test Conditions and Operational Test Setup).

Test Personal: The testing is being conducted by IPSC Engineering who is leasing test quality gas analyzers from Power Generation Technologies (PGT).

Test Coordinators- Aaron Nissen and Garry Christensen
Gas Analyzers and Test Grid- Garry Christensen & Rob Jeffery
Tech Support, Coal & Fly Ash sample collection- Dave Spence & Bernell Warner
Fly Ash Sample Collection- - ISG Rod Hansen, Rick Fowles/ Kurt Aldredge
OFA System Controls and Dampers- Ken Neilson & Phil Hailes
Babcock Power interface- Dan Coates

Test Method- Testing will utilize the station "PI" data acquisition system to document test conditions and collect plant operating data. In addition, a test grid is setup at the boiler outlet (11^{th} floor) using 14 test probes at four different depths for a total of 56 points. The gas sampling system is setup with both east and west side averaging systems consisting of bubblers, vacuum pumps, chillers and desiccant filters. The mixed, cooled, dry, filtered gas samples are then analyzed for O2, CO2, CO and Nox and data collected and stored via data acquisition system. This information is then dumped to a spreadsheet for statistical analysis and averaging. Thermocouples are also at each location to get averaged boiler gas outlet temperatures. Additionally, we have a test setup at the base of the Stack to collect a CO gas sample at the 355' level using the Environmental Group's RATA Test Trailer. This sample is also conditioned and analyzed and stored on a data acquisition system for analysis.

NOTE, we will utilize the O2 test grid measurement at the boiler outlet to refine test conditions (compared to control room O2 probes) . We are seeing a bias between station O2 and the O2 at the boiler outlet grid. The O2% at the boiler outlet, however, agrees with higher Air Flow shown in CCS, correlates with the higher ID Fan rpm and amps, plus correlates with higher NOx and low CO levels. As part of the testing, we will try to reconcile why we have such high station O2 levels.

In addition to east and west side averaged gas conditions, individual test points will also be taken during a separate test to develop backpass test grid profile. These profiles will include O2, CO and temperatures which will be used to troubleshoot and diagnosis burner dual register setup, secondary air flow side to side splits, plus overfire air flow balancing issues.

Boiler Testing- Time Frames Each test point needs at least 2 hours, allowing ½ to 1 hour between test points to lower O2, pull fly ash and sootblow for temperatures. ½ to 1 hour is needed to stablize operating conditions. Each test needs a minimum of a hour of very steady state test conditions. Prior to each test period (daily), the gas analyzers need to be started, warmed up and calibrated. This process takes 1 to 1 ½ hours to complete. During this time, all tubing, bubblers, chillers, desiccant filters, and dust filters will be checked out.

OFA System Damper Positioning- 1/3 and 2/3 dampers plus OFA secondary air inlet dampers will need to be moved and position checked during the course of the testing. The 1/3 dampers have had actuators replaced with larger heavy duty drives. They have been recently installed and stroked, but several (NW & SW) have been hanging up. There is some concern about linkages breaking internally and unable to achieve good balanced OFA flows.

Fly Ash Samples will also be taken and correlated with the test results. We will need 2 Operators to help support fly ash sample collection. ISG will be collecting the fly ash samples at each of the different test points. All fly ash hopper rows need to be available (no maintenance work) and <u>hoppers will need to be pulled down prior to the start of the first test</u> (night shift pulling prior to 7:00 am each day) and then hoppers will be pulled between each test point (while samples are being taken). Depending on the test series, bottom ash samples will also be collected as part of the boiler performance testing evaluation.

Coal Samples will also be taken throughout each test period at the coal feeder inlet spouts (test taps installed special for testing). Note: there maybe a certain amount of coal spillage created while collecting these coal samples. We will ensure coal spillage will be cleaned up at the end of each day.

Flue Gas Sampling Test Grid Equipment (11th floor, rear of the boiler, west side)- We have rented precision gas analyzers to be used for burner and OFA tuning and testing, this equipment also includes data acquisition system and Lap Top computer. There is also calibration bottles (O2, NOX, & CO), packing crates & boxes, hoses and tubing, tools, tool cart, power supply, air hoses & lances, bubblers, chillers, desiccant filters, vacuum pumps, etc., etc. We are running a swamp cooler (with water flow) plus an air handling fan on the 11th floor NW corner to keep analyzers and test personnel from over-heating. Please help us keep an eye on this equipment. This test equipment is worth several $100K, so please DO NOT WASH DOWN this area, unless we are notified. We can accommodate a washdown (as we have in the past), be need to <u>put the system to bed</u> (power down equipment, disconnect power supplies, box and crate analyzers, etc.) and cover everything else up with plastic tarps.

Maintenance Support Requirements-
Pulverizers- Pulverizer U1F is down for major overhaul. If there are problems with any other pulverizer, we will need priority attention placed on returning that pulverizer back to service.

Baghouse Fly Ash Handling- during this test series (day shift) , we need to have both east and west fly ash handling systems available for full service.

All other normally operating equipment- needs to be in-service and operating. During this test series, we cannot test with a load derate which would effect Unit capability of 950 MWg. If this is not possible (or is unavoidable) , we need to know so that we can re-schedule the testing series to a later date.

I&C Support Requirements-
O2 Probe calibrations and technical support- We need the 3 bad O2 probes replaced and the weekly PM completed (troubleshooting walkdown and calibration). If we have additional problems or concerns, we will need technical support.

Coal Feeder calibrations- all coal feeders have been scheduled for calibrations prior to the test series (during the pulverizer shutdowns for dynamic restrictor installation)

Computer Group Support Requirements-
PI computer availability- The PI and Foxboro 1A computer systems need to be up and running. Please do not schedule and conduct backups during this period.

Operational Test Setup- Boiler OFA & Platen Tests

Load (MWgross) 950
Controls– boiler to local (or manual),
Boiler Test Objective is for stable boiler/ throttle pressure and let MWs float.
(throttling control valves okay- this is not a turbine test at valves wide open)
Overfire Air System to manual

Throttle Press & Control Valve Position	as needed for load
Main Steam Temp (F)	1005
Main Steam spray (kpph)	<200
Hot Reheat Temp (F)	1005
Reheat Sprays (kpph)	0
Bias Dampers (%)	may have to take PRH side to manual & set between 30- 45%, to control RH temps

Sootblowing- as required to achieve Main Stm, HRH and FEGT temps
No sootblowing (during each test period of 2 hrs), sootblowing is allowed between each test
NOTE: for 950 MWg operation, need to allow SH & RH areas to get dirtier, but blow waterwalls to achieve FEGT (furnace exit gas temp) and EGOT (economizer gas outlet temp)

FEGT target (F)	2200, controlled by waterwall sootblowing
EGOT target (F)	760

O2 levels (measured at boiler outlet with test equipment)
VARIES from 3.5%, 3.0%, & 2.5% at 2 hour increments
Note: there is a discrepancy between station instrumentation and local test analyzers (local reads are higher by 0.5% to 1.0% O2)

Over Fire Air System local control
1/3 & 2/3 port dampers, VARIES from
- 5% OFA (baseline), both closed or inlet dampers closed
- 10% (1/3 damper open- balanced flow all 4 corners, 2/3 damper closed)
- 12%(2/3 damper open- throttled & balanced, 1/3 damper closed)
- 14% (2/3 dampers open- balanced flow all 4 corners, 1/3 damper closed)

NOx level target (#/mbtu)	< 0.38
CO (ppm)	< 100
Primary Air Duct Press ("wc)	43

Pulverizer Configuration- 7 I/S, U1F o/s (Sec air damper – 10%)
Note- Remove all pulverizer biasing (unless absolutely necessary due to unmanageable coal dribble)
NOTE: U1 F pulverizer o/s for major overhaul

Need all normally running equipment in-service (7 Pulv, all FD, PA & ID fans, etc.). This ensures good uniform air and gas flow distribution.

No Boiler Blowdown during the testing period
Isolate Unit 1 CRH to aux steam supply and route all building heat (if in service) drains to Unit 2.

Coal Supply – No Westridge or Dugout coal, need straight SUFCO for best emission results
No Rocks, please

NOTES (recaps):

1) Fly Ash Samples- need to be taken during each test period (need support of 2 Operators for fly ash sample collection). Fly Ash Hoppers need to be pulled down prior to the test (night shift) and between each test point. ISG will be collecting the fly ash samples at each test points. All fly ash hopper rows need to be available (no maintenance work)

2) Coal Supply- coal quality needs to be consistent (all from the same mine source) preferably from SUFCO.

3) Coal Samples will also be taken at each test point at the coal feeder inlet (new test coal sample collection ports). Note: there may be a certain amount of coal spillage created while collecting these coal samples.

4) Bottom ash samples will also be collected during some of the tests.

5) Do not washdown boiler in the backpass areas, due to test equipment, analyzers and computers.

6) PI computer system – needs to be up and running, no downtime or backups

7) CEM system – PI interface needs to be working

BOILER TEST CONDITIONS SUMMARY

IGS Unit 1 Boiler Overfire Air System and SH Platen Extension POST- OUTAGE Testing

State of Utah Required Testing (to demostrate no increase in CO due to installation of Overfire Air System)
OFA Diagnostics Testing (to determine best spot to operate and develop control curves)
Each test point needs 1 1/2 hour, allowing ½ hour between test points to lower O2, pull fly ash and sootblow for temperatures

			TEST CONDITIONS		TARGET	PRELIMINARY TEST- CR						TEST GRID	
TEST #	DATE	TIME	OFA%	OFA Dampers	O2% CR	O2%- E CR	O2%- W CR	O2% Air Flow	O2% SetPt	OFA%	Nox CEM	O2%- E TEST	O2%- W
Test # 1 (Day1-T1)	09/06/2003 Day 1- Sat	8:15- 9:30	5.0%	closed- 1/3, 2/3 & inlet dampers	3.0	2.8	3.2	86.3	61.0	5.3	0.534		
Test # 2 (Day1-T2)	09/06/2003 Day 1- Sat	10:15- 1130	10.0%	1/3 open- balanced, 2/3 closed, inlets open	3.0	2.6	3.3	85.6	61.0	10.6	0.436		
Test # 3 (Day1-T3)	09/06/2003 Day 1- Sat	12:30- 13:30	14.0%	2/3 open- balanced, 1/3 closed, inlets open	3.0	1.9	3.5	86.0	61.0	14.4	0.381		
Test # 4 (Day1-T4)	09/06/2003 Day 1- Sat	14:15- 15:30	12.0%	2/3 open- throttled, 1/3 closed, inlets open	3.0	2.8	3.0	85.6	61.0	12.1	0.416		
Test # 5 (Day1-T5)	09/06/2003 Day 1- Sat	15:45- 16:45	12.0%	2/3 open- throttled, 1/3 closed, inlets open	2.5	2.5	2.7	81.9	55.5	11.9	0.386		
Test # 6 (Day2-T1)	09/7/2003 Day2- Sun	7:45- 9:00	5.0%	closed- 1/3, 2/3 & inlet dampers	2.5	2.3	3	82	41.0	4.6	0.426		
Test # 7 (Day2-T2)	09/7/2003 Day2- Sun	9:45- 10:45	10.0%	1/3 open- balanced, 2/3 closed, inlets open	2.5	1.9	2.9	84.1	43.0	9	0.377		
Test # 8 (Day2-T3)	09/7/2003 Day2- Sun	13:05- 14:05	14.0%	2/3 open- balanced, 1/3 closed, inlets open	2.5	2.3	2.5	85.3	44.2	12.6	0.354		
Test # 9 (Day2-T4)	09/7/2003 Day2- Sun	15:15- 16:15	14.0%	2/3 open- balanced, 1/3 closed, inlets open	2.0	1.8	1.9	82.1	39.0	12.5	0.317		
Test # 10 (Day2-T5)	09/7/2003 Day2- Sun	17:00- 18:00	12.0%	2/3 open- throttled, 1/3 closed, inlets open	2.0	1.7	2.2	80.3	39.0	8.8	0.347		
Test # 11 (Day3-T1)	09/8/2003 Day3- Mon	8:15- 9:30	10.0%	1/3 open- balanced, 2/3 closed, inlets open	2.0	1.4	2.7	78.7	36.0	9	0.329		
Test # 12 (Day3-T2)	09/8/2003 Day3- Mon	10:30- 11:30	5.0%	closed- 1/3, 2/3 & inlet dampers	2.0	2	2.2	79.5	37.5	4.6	0.384		
Test # 13 (Day3-T3)	09/8/2003 Day3- Mon	12:30- 13:45	5.0%	closed- 1/3, 2/3 & inlet dampers	1.5	1.8	1.8	76.8	24.5	4.5	0.356		
Test # 14 (Day3-T4)	09/8/2003 Day3- Mon	14:30- 15:30	10.0%	1/3 open- balanced, 2/3 closed, inlets open	1.5	1.4	2.4	77.6	26.1	7.9	0.304		
Test # 15 (Day3-T5)	09/8/2003 Day3- Mon	16:15- 17:15	10.0%	1/3 open- balanced, 2/3 closed, inlets open	3.5	2.5	4.2		47.5	8.7	0.396		
Test # 16 (Day4-T1)	09/9/2003 Day4- Tues	7:30- 8:45	5.0%	closed- 1/3, 2/3 & inlet dampers	3.5	2.7	3.2	85.1	44.0	4.6	0.404		
Test # 17 (Day4-T2)	09/9/2003 Day4- Tues	9:45- 11:00	14.0%	2/3 open- balanced, 1/3 closed, inlets open	3.5	3.6	4.4	90.8	52.6	11.6	0.38		
Test # 18a (Day4-T3)	09/9/2003 Day4- Tues	14:15- 14:45	12.0%	2/3 open- throttled, 1/3 closed, inlets open	3.0	2.7	2.7	85.4	46.3	10.9	0.376		
Test # 18b (Day4-T3)	09/9/2003 Day4- Tues	14:30- 16:30	12.0%	2/3 open- throttled, 1/3 closed, inlets open									

NOTE: O2 and CO% based on Boiler Outlet Grid values
Coal Supply Requirements- NO WestRidge or Dugout, need SUFCO coal straight for best results
Pulv U1 F o/s

IP10_003371

EQUIPMENT BID AND RECORD

4HR TIME FORMAT

equested by Aaron Nissen — Div. IPSC Sec. IGS — Submitted by ______ Operator ______ Time ______ Date

☐ Out of Service Clearance O.K. TO Garry Christensen/ Aaron Nissen (Responsible Party) — Div. IPSC Sec. IGS

QUIPMENT REQUESTED: Unit 1 Boiler Overfire Air Tests,, at 950 MW gross- 3 days, MStm Temp 1005 F/ HRH 1005 F/ throttled conditions.

ATURE OF WORK: State of Utah Required Testing for the Overfire Air System

ID Time

ROM: Saturday	06:00- 19:00 MDST	09/06/03	**TO:** Tuesday	06:00- 19:00 MDST	09/9/03
	Time	Date		Time	Date

WORK Time

ROM: Saturday	06:30- 18:30 MDST	09/06/03	**TO:** Thursday	06:30- 16:30 MDST	09/9/03
	Time	Date		Time	Date

MST=Mountain Standard MDST=Mountain Daylight PST=Pacific Standard PDST=Pacific Daylight

PREPARATION REQUIRED: Throttle Press& valve position as needed for load / Main Steam Temp 1005F/ Reheat 1005 F, 7 pulverizer operation (pulv H o/s). Boiler (in local), control reheat temps bias dampers (no reheat sprays), no sootblowing during each test period of 2 hours), minimize convection pass sootblowing prior to each test (previous shift) so able to achieve Mstm HRH temps at 950 MW, main steam temperature control by sprays is ok (but best to minimize, no im sprays if possible)), no boiler drum blowdown during the test. Remove all pulverizer and fan biases. Isolate Unit 1 CRH to aux steam supply.
OAL- no Westridge or Dugout (perference is straight SUFCO)

BID APPROVED:

PS Supv. ______ Time ______ Date ______ — Removed by ______ Time ______ Date ______

upt. ______ Time ______ Date ______ — Issued to ______ Time ______ Date ______

Dispatcher ______ Time ______ Date ______ — Returned by ______ Time ______ Date ______

EQUIPMENT NORMAL: ______ Time ______ Date — By ______ Operator ______ Supv.

emarks: ______

TEST EQUIPMENT LIST

Description of precision Test Equipment rented for the U1 Boiler Overfire Air / Burner Testing (2/03- 9/03)

Boiler Back-pass Data Acquisition System-
HP/ Agilent 34970A Data Acquisition/ Switch Unit ID #20312

Data Acquisition System Software- Power Generation Technologies (PGT) DAS version 3, data acquisition system software for Windows

Boiler Back-pass Gas Sampling Analyzers:
East Side Analyzers

NO/ NO2/ NOX -
Advanced Pollution Instrumentation Inc. (API) model 200AH- NO/ NO2/ NOX chemiluminescence analyzer, serial #335

CO/ CO2 - (low range CO analyzer)
California Analytical Instruments, Inc. (CAI) / Fuji Electric ZRH- infrared non-dispersive gas (NDIR) CO/ CO2 dual channel analyzer, serial #N6G2393C

O2 -
California Analytical Instruments, Inc. (CAI) model 100F- galvanic fuel cell oxygen analyzer, serial #8M05001

CO (hi range)-
Thermo Environmental Instrments Inc.(TEI) model 48C- Infrared gas filter correlation (GFC) CO analyzer, serial #48C-71190-368

West Side Analyzers

NO/ NO2/ NOX -
Advanced Pollution Instrumentation Inc. (API) model 200AH- NO/ NO2/ NOX chemiluminescence analyzer, serial #461

CO/ CO2 - (low range CO analyzer)
California Analytical Instruments, Inc. (CAI) / Fuji Electric ZRH infrared non-dispersive gas (NDIR) CO/ CO2 dual channel analyzer, serial #N6G2394C

O2 -
California Analytical Instruments, Inc. (CAI) model 100F- galvanic fuel cell oxygen analyzer, serial #8M05002

CO (hi range)-
Thermo Environmental Instrments Inc.(TEI) model 48C- Infrared gas filter correlation (GFC) CO analyzer, serial #48C-70493-366

Stack Data Acquisition System -

Yokogawa MobileCorder model MV106, serial #12W942620

Stack CO (low range) -

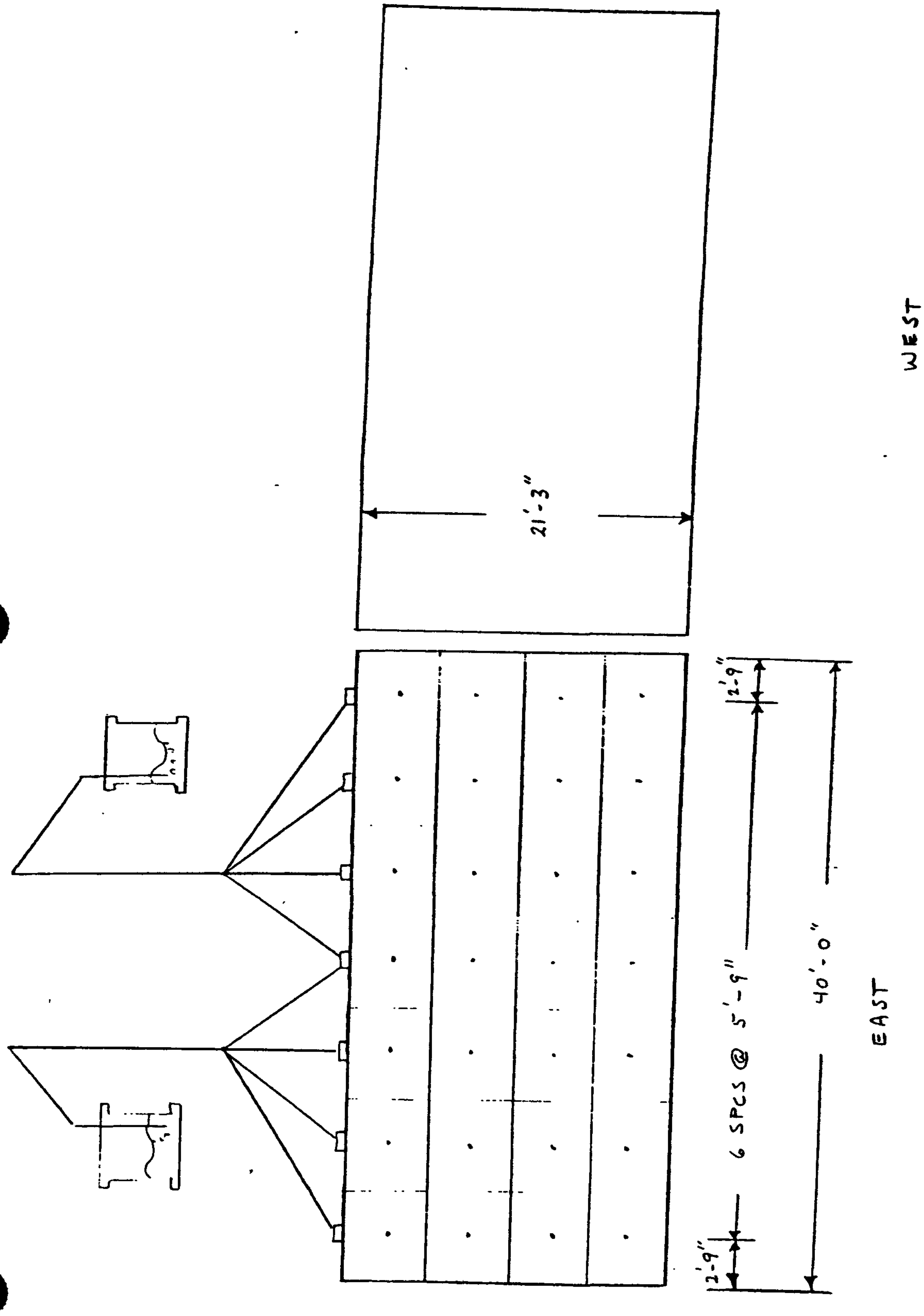
Advanced Pollution Instrumentation Inc. (API) model 300 Infrared gas filter correlation (GFC) CO analyzer, serial #1369

Spare O2 Analyzer -

Teledyne Analytical Instruments model 326RA oxygen analyzer

BABCOCK & WILCOX

GENERAL CALCULATIONS



STOMER
INTERMOUNTAIN POWER PROJECT

FILE NO.
RB-614

SUBJECT
ECONOMIZER GAS OUTLET SAMPLING GRID

PREPARED BY
JDR

DATE
5-25-77

CERTIFICATE OF CALIBRATION

Manufacturer: Agilent	Calibration Performed For:
Model No.: 34970A	Intermountain Power Service Corporation
Serial No.: US37047275	850 W. Brush Wellman Road
PGT Asset No.: 20312	Delta, UT 84624-9546
Customer ID#: HP-DAS-53	
Description: Data Acquisition/Switch Unit	Contract/P.O.#: 010410.30

CALIBRATION INFORMATION

Report Number: 20312-020603FL Result: **PASS** Calibration Performed By: Richard Hutson
Cal Date: 02/06/2003 Temperature: 22.0°C As Found and/or As Left: Found-Left
Due Date: 02/06/2004 Humidity: 42 % Seals Intact: Yes Location: In-House

Procedure: HP/Agilent 34970A: CAL VER RS-232/5520A (1 year) Revision: 0 - 04/17/01

Notes: Unit within tolerances as found and as left.

This instrument was calibrated in accordance with ANSI/NCSL Z540-1-1994, ISO/IEC Guide 17025 and the documentation requirements of ISO 9000, using laboratory standards that are traceable to the National Institute of Standards and Technology, nationally recognized standards or natural physical constants, or are derived using self-calibrating ratio techniques.

Uncertainties of the laboratory standards are calculated at a coverage factor (k) of 2, corresponding to a confidence interval of approximately 95%. The collective uncertainty of the standard(s) utilized in this procedure does not exceed 25% (TUR >4:1) of the unit under tests (UUT) accuracy specification(s) unless otherwise specified in the test data or notes.

A calibration due date; determined by the customer, manufacturers specifications or instrument history; is provided for reference only and does not imply continued conformance to specification.

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Calibration Technologist Reviewed/Approved

STANDARDS USED

Asset No.	Description	Cal Date	Cal Due Date
10154	Fluke 5520A-SC1100 Multi-Product Calibrator	03/12/2002	03/12/2003

TEST DATA

STANDARD PARAMETER	TRUE VALUE	UUT READING	TEST TOLERANCE	ERROR (% of TOL)	TEST RESULT PASS/FAIL	EXPANDED UNCERTAINTY	TUR
CALIBRATION VERIFICATION							
SELF TEST							
0.0status		0.0		0	PASS		
ZERO OFFSET TESTS							
mADC Range							

Power Generation Technologies 200 Tech Center Drive Knoxville, TN 37912 Tel: (865) 688-7900 Fax: (865) 687-8977

STANDARD PARAMETER	TRUE VALUE	UUT READING	TEST TOLERANCE	ERROR (% of TOL)	TEST RESULT PASS/FAIL	EXPANDED UNCERTAINTY	TUR
0.00000mA		-0.00008		4	PASS		
100 mADC Range							
0.00000mA		-0.00010		2	PASS		
1 ADC Range							
0.000000A		-0.000004		4	PASS		
100 mVDC Range							
0.0000mV		-0.0015		37	PASS		
1 VDC Range							
0.000000V		-0.000002		22	PASS		
10 VDC Range							
0.00000V		0.00000		3	PASS		
100 VDC Range							
0.0000V		-0.0000		2	PASS		
300 VDC Range							
0.000V		-0.000		0	PASS		
100 Ohm Range, 2-Wire							
0.0000 Ohm		-0.0000		0	PASS		
1 kOhm Range, 2-Wire							
0.000000 kOhm		0.000155		15	PASS		
10 kOhm Range, 2-Wire							
0.00000 kOhm		0.00014		13	PASS		
100 kOhm Range, 2-Wire							
0.0000 kOhm		0.0000		1	PASS		
1 MOhm Range, 2-Wire							
0.000000 MOhm		0.000000		2	PASS		
10 MOhm Range, 2-Wire							
0.000000 MOhm		-0.000010		10	PASS		
100 MOhm Range, 2-Wire							
0.000000 MOhm		0.000000		0	PASS		
100 Ohm Range, 4-Wire							
0.0000 Ohm		-0.0005		12	PASS		
1 kOhm Range, 4-Wire							
0.000000 kOhm		-0.000001		5	PASS		
[illegible] kOhm Range, 4-Wire							

STANDARD PARAMETER	TRUE VALUE	UUT READING	TEST TOLERANCE	ERROR (% of TOL)	TEST RESULT PASS/FAIL	EXPANDED UNCERTAINTY	TUR
0.00000 kOhm		-0.00001		11	PASS		
100 kOhm Range, 4-Wire							
0.0000 kOhm		-0.0001		12	PASS		
1 MOhm Range, 4-Wire							
0.000000 MOhm		-0.000001		5	PASS		
10 MOhm Range, 4-Wire							
0.00000 MOhm		-0.00000		3	PASS		
100 MOhm Range, 4-Wire							
0.0000 MOhm		0.0000		0	PASS		
DC VOLTAGE - Gain Verification							
100mV Range							
100.0000mV		99.9988	9uV	13	PASS	5.0E-006	1.8
1V Range							
1.000000V		0.999997	47uV	6	PASS	1.6E-005	2.9
10V Range							
10.00000V		10.00004	400uV	9	PASS	1.7E-004	2.4
-10.00000V		-10.00004	400uV	10	PASS	1.7E-004	2.4
[illegible]V Range							
100.0000V		100.0009	5.1mV	17	PASS	2.3E-003	2.2
300V Range							
300.0000V		300.0016	22.5mV	7	PASS	5.9E-003	3.8
AC VOLTAGE - Gain Verification							
100mV Range							
10.0000mV @ 1kHz		10.0029	46uV	6	PASS	2.2E-005	2.1
100.0000mV @ 1kHz		99.9858	100uV	14	PASS	3.7E-005	2.7
100.0000mV @ 50kHz		99.9764	170uV	14	PASS	5.7E-005	3.0
1V Range							
1.000000V @ 20Hz		0.999711	1mV	29	PASS	3.6E-004	2.7
1.000000V @ 1kHz		0.999915	1mV	8	PASS	2.2E-004	
1.000000V @ 20kHz		1.000025	1mV	2	PASS	2.6E-004	3.8
1.000000V @ 50kHz		1.000032	1.7mV	2	PASS	3.6E-004	
1.000000V @ 100kHz		1.000259	6.8mV	4	PASS	8.4E-004	
1.000000V @ 300kHz		1.007650	45mV	17	PASS	3.0E-003	
10V Range							
0.10000V @ 1kHz		0.10076	14mV	5	PASS	3.7E-005	
1.00000V @ 1kHz		1.00000	4.6mV	0	PASS	2.2E-004	
10.00000V @ 1kHz		9.99899	10mV	10	PASS	2.2E-003	
[illegible]0.00000V @ 50kHz		9.99808	17mV	11	PASS	4.2E-003	
[illegible].00000V @ 10Hz		9.99788	14mV	15	PASS	3.8E-003	3.7

STANDARD PARAMETER	TRUE VALUE	UUT READING	TEST TOLERANCE	ERROR (% of TOL)	TEST RESULT PASS/FAIL	EXPANDED UNCERTAINTY	TUR
100V Range							
100.0000V @ 1kHz		99.9736	100mV	26	PASS	2.1E-002	
100.0000V @ 50kHz		99.9542	170mV	27	PASS	3.6E-002	
300V Range							
300.000V @ 1kHz		299.958	420mV	10	PASS	5.9E-002	
300.000V @ 50kHz		299.869	720mV	18	PASS	9.6E-002	
4-WIRE OHMS - Gain Verification							
100 Ohm Range							
100.0000 Ohm		99.9994	14 mOhm	4	PASS	4.3E-003	3.3
1 kOhm Range							
1.000000 kOhm		0.999992	110 mOhm	7	PASS	3.0E-002	3.7
100.000 Ohm		100.000	20 mOhm	2	PASS	4.3E-003	
120.000 Ohm		119.999	21.9999 mOhm	4	PASS	5.5E-003	
140.000 Ohm		139.998	23.9998 mOhm	8	PASS	6.0E-003	4.0
160.000 Ohm		159.998	25.9998 mOhm	9	PASS	6.6E-003	4.0
180.000 Ohm		179.997	27.9997 mOhm	12	PASS	7.2E-003	3.9
200.000 Ohm		199.996	29.9996 mOhm	13	PASS	7.7E-003	3.9
10 kOhm Range							
10.00000 kOhm		9.99999	1.1 Ohm	1	PASS	3.0E-001	3.7
kOhm Range							
100.0000 kOhm		100.0008	11 Ohm	7	PASS	3.0E+000	3.7
2-WIRE OHMS - Gain Verification							
100 Ohm Range							
100.0000 Ohm		100.3916	1.014 Ohm	39	PASS	4.2E-003	
1 kOhm Range							
1.000000 kOhm		1.000383	1.11 Ohm	34	PASS	3.0E-002	
10 kOhm Range							
10.00000 kOhm		10.00038	2.1 Ohm	18	PASS	3.0E-001	
100 kOhm Range							
100.0000 kOhm		100.0012	12 Ohm	10	PASS	3.0E+000	
1 MOhm Range							
1.000000 MOhm		1.000003	111 Ohm	3	PASS	3.6E+001	3.1
10 MOhm Range							
10.00000 MOhm		9.99896	4.1 kOhm	25	PASS	1.4E+003	3.0
100 MOhm Range							
100.0000 MOhm		99.7573	810 kOhm	30	PASS	5.3E+004	

QUENCY - Gain Verification

STANDARD PARAMETER	TRUE VALUE	UUT READING	TEST TOLERANCE	ERROR (% of TOL)	TEST RESULT PASS/FAIL	EXPANDED UNCERTAINTY	TUR
[redacted]mV Range							
[redacted]00.0000Hz @ 10mV		99.9846	100mHz	15	PASS	2.6E-004	
1V Range							
100.0000kHz @ 1V		100.0001	10Hz	1	PASS	2.6E-001	
DC CURRENT - Gain Verification							
10mA Range							
10.00000mA		10.00022	7uA	3	PASS	1.3E-006	
100mA Range							
100.0000mA		100.0039	55uA	7	PASS	1.3E-005	
1A Range							
1.000000A		0.999998	1.1mA	0	PASS	2.4E-004	
AC CURRENT - Gain Verification							
10mA Range							
10.00000mA @ 1kHz		9.99566	14uA	31	PASS	6.0E-006	2.3
100mA Range							
100.0000mA @ 1kHz		100.0267	600uA	4	PASS	6.0E-005	
1A Range							
[redacted]000000A @ 1kHz		1.000133	1.4mA	10	PASS	6.0E-004	2.3
TYPE K TC INPUT VERIFICATION - (34901A Multiplexer)							
Channel 00 (101)							
0.0degC		0.3	1degC	31	PASS	1.7E-001	
300.0degC		300.3	1degC	33	PASS	2.7E-001	3.8
600.0degC		600.3	1degC	33	PASS	2.7E-001	3.8
Channel 09 (110)							
0.0degC		0.0	1degC	2	PASS	1.7E-001	
300.0degC		300.1	1degC	8	PASS	2.7E-001	3.8
600.0degC		600.1	1degC	9	PASS	2.7E-001	3.8
Channel 20 (201)							
0.0degC		0.1	1degC	7	PASS	1.7E-001	
300.0degC		300.1	1degC	12	PASS	2.7E-001	3.8
600.0degC		600.1	1degC	11	PASS	2.7E-001	3.8
Channel 29 (210)							
0.0degC		0.1	1degC	10	PASS	1.7E-001	
300.0degC		300.1	1degC	13	PASS	2.7E-001	3.8
600.0degC		600.1	1degC	15	PASS	2.7E-001	3.8
Channel 40 (301)							
0.0degC		-0.5	1degC	50	PASS	1.7E-001	
300.0degC		299.6	1degC	43	PASS	2.7E-001	3.8
600.0degC		599.6	1degC	40	PASS	2.7E-001	3.8
Channel 49 (310)							
0.0degC		0.0	1degC	3	PASS	1.7E-001	
[redacted]0.0degC		300.1	1degC	10	PASS	2.7E-001	3.8
[redacted]0.0degC		600.1	1degC	10	PASS	2.7E-001	3.8

3 SPECIFICATIONS, WARRANTY

3.1 Specifications

Operating Modes	NO/NO_x switching mode, NO only mode, NO_x only mode
Ranges	In 1 ppm increments from 5 ppm to 5,000 ppm Single range, independent ranges or autoranging
Noise at zero	0.02 ppm RMS
Noise at span	<0.2% of reading RMS above 20 ppm
Detection Limit(Note 1)	0.04 ppm RMS
Zero Drift (Note 2)	<0.2% full scale/24 hours
Zero Drift (Note 2)	<0.4% full scale/7 days
Span Drift (Note 2)	<1% FS/24 hours
Lag Time	
Switching Mode	20 sec (Note 3)
NO_x mode	4 sec (Note 3)
Response Time	
Switching Mode	95% in < 40 sec (Note 3)
NO_x mode	95% in < 10 sec (Note 3)
Sample Flow Rate	290 ±10 cc/min (Including bypass)
Linearity	1% of full scale
Precision	0.5% of reading
Temperature Range	5-40^{O} C
Humidity	0-95% RH non-condensing
Temp Coefficient	< 0.1% per ^{O} C
Voltage Coefficient	< 0.1% per V
Dimensions HxWxD	7"x17"x23.6" (18 cm x 43 cm x 61 cm)
Weight, Analyzer	43 lbs (20 kg)
Weight, Pump Pack	16 lbs (7 kg)
Power, Analyzer	100 V~ 50/60 Hz, 120 V~ 60 Hz, 220 V~ 50 Hz, 240 V~ 50 Hz, 200 watts
Power, Analyzer[4]	230 V~ 50 Hz, 2.5A
Power, Ext Pump	110 V~ 60 Hz, 220 V~ 50 Hz, 240 V~ 50 Hz, 295 watts
Power, Ext Pump[4]	230 V~ 50 Hz, 2.5A
Environmental	Installation Category (Over-voltage Category) II Pollution Degree 2
Analog Resolution	1 part in 2048 of selected voltage or current range
Recorder Output	0-100 mV, 0-1, 5, 10v, bipolar
Current Loop Option	4-20ma isolated
Status	12 Status Outputs from opto-isolator
Measurement Units	ppm, mg/m^3

1. Defined as twice the zero noise level.
2. At constant temperature and voltage.
3. Lag & response times longer for external converter option.
4. Electrical ratings for CE Mark compliance.

West Grid NOX

ASHTEAD Technology RENTALS

Calibration Certificate

Equipment Information:

CUSTOMER: Environmental Systems Corp
INSTRUMENT: API NOX Analyzer
MODEL: 200
SERIAL #: 461 / R5093

Calibration Standards:

STANDARD:	ZeroAir #314-05695	RESPONSE:	0.0 ppm NOx, NO, NO2
STANDARD:	199 ppm NO #861-81674	RESPONSE:	199.0 ppm NOx, NO
STANDARD:	203 ppm NO2 #861-65815	RESPONSE:	194.9 ppm NO2
STANDARD:	_________________	RESPONSE:	_________________

TECHNICIAN: D.Stiles
DATE: 7 February 2003
DUE DATE: N/A

NOTES:
Unit performs within specifications:__X__, Flow OK:__X__.
Converter Efficiency: 96% .

This instrument has been calibrated according to the calibration procedure as described in the operation manual.

☒Ashtead Technology Rentals
1057 East Henrietta Road
Rochester, NY 14623
585-424-2140

☐Ashtead Technology Rentals
18195 McDurmott East, Suite A/B
Irvine, CA 92614
949-955-3930

☐Ashtead Technology Rentals
3311 Preston Avenue
Pasadena, TX 77505
281-991-1448

West Grid NOx

Table 2-1: Final Test and Calibration Values

TEST Values	Observed Value	Units	Nominal Range	Reference Section
RANGE	200	ppm	5-5000	5.3.4
NOISE	.005	ppm	0.0 - 0.2	9.1.1, Table 9-1, 9.2.5
SAMP FLW	301	cc/min	300 ± 50 (Default) 550 ± 50 (Optional)	9.3.7, Table 9-1
OZONE FL	247	cc/min	250 ± 15	9.3.6
PMT	34.9	mV	0-5000	9.3.8
AUTOZERO	37.6	mV	-10 to +50	4.1
HVPS	488	V	400 - 700 constant	9.3.8.5
DCPS	2543	mV	2500 ± 200	9.3.5
RCELL TEMP	50.9	°C	50 ± 2	9.3.8.2
BLOCK TEMP	49.5	°C	50 ± 2	9.3.4.1
BOX TEMP	30.0	°C	8-48	9.3.4.1
PMT TEMP	7.1	°C	7 ± 1	9.3.8.4
CONV TEMP	702.7	°C	700 ± 10 (Std) 315 ± 5 (Moly)	9.3.4.1
RCEL PRES	5.1	IN-Hg-A	2 - 10 constant	9.3.7
SAMP PRES	29.3	IN-Hg-A	25 - 30 constant	9.3.7
Electric Test & Optic Test				
Electric Test				
PMT Volts	1990	mV	2000 ± 200	9.1.3.2
NO Conc	248	ppm	250 ± 25	9.1.3.2
NO_x Conc	248	ppm	250 ± 25	9.1.3.2
OPTIC TEST				
PMT Volts	100.7	mV	100 ± 20	9.1.3.3
NO Conc	12.67	ppm	12.5 ± 2	9.1.3.3
NO_x Conc	12.92	ppm	12.5 ± 2	9.1.3.3

(table continued)

Analog Output = 10.00V @ 100% F.S. For NOx, NO, NO2

IP10_003383

West NOx

Table 2-1: Final Test and Calibration Values (Continued)

Parameter	Observed Value	Units	Nominal Range	Reference Section
NO Span Conc	199	ppm	0.5 - 5000	Table 7-3
NO_x Span Conc	199	ppm	0.5 - 5000	Table 7-3
NO Slope	0.995	-	1.0 ± 0.3	7.1, 7.9
NO_x Slope	0.990	-	1.0 ± 0.3	7.1
NO Offset	1.1	mV	± 25	7.1, 7.2
NO_x Offset	1.4	mV	± 25	7.1, 7.2
Conv Efficiency	96	%	0.75 - 1.10	7.10, 5.2.2.6
Noise at Zero	.005	ppm	0.0 - 0.2	Table 9-1
Noise At Span	.025	ppm	0.1 - 0.5	Table 9-1
Measured Flows				
Sample Flow	298	cc/min	50 ±20	9.3.7, Figure 9-8
Bypass Flow	(total)	cc/min	250 (Std) 500 (Optional)	Figure 8-4
Ozone Flow	—	cc/min	250 ± 15	9.3.7, Figure 9-8

Factory Installed Options	Option Installed
Power Voltage/Frequency	115V/60Hz
Rack Mount, w/ Slides	
Rack Mount, w/ Ears Only	
Rack Mount, External Pump w/o Slides	
Stainless Zero/Span Valves	
4-20 mA Current Loop Output, Isolated	
Bypass flow 500 cc/min	
Molybdenum Converter	
Desiccant Canister - O3 generator	

PROM # 2AAE95TD.1-1 Serial # 461/R5093

Date 7 Feb 03 Technician D. Stiles

Cast Grid NOx

ASHTEAD Technology RENTALS

Calibration Certificate

Equipment Information:

CUSTOMER: Environmental Systems Corp
INSTRUMENT: API NOX Analyzer
MODEL: 200
SERIAL #: 335 / R3756

Calibration Standards:

STANDARD:	ZeroAir #314-05695	RESPONSE:	0.0 ppm NOx, NO, NO2
STANDARD:	199 ppm NO #861-81674	RESPONSE:	199.0 ppm NOx, NO
STANDARD:	203 ppm NO2 #861-65815	RESPONSE:	191.2 ppm NO2
STANDARD:	____________	RESPONSE:	____________

TECHNICIAN: D.Stiles
DATE: 6 February 2003
DUE DATE: N/A

NOTES:
Unit performs within specifications:__X__, Flow OK:__X__.
Converter Efficiency: 94% .

This instrument has been calibrated according to the calibration procedure as described in the operation manual.

☒ Ashtead Technology Rentals
1057 East Henrietta Road
Rochester, NY 14623
585-424-2140

☐ Ashtead Technology Rentals
18195 McDurmott East, Suite A/B
Irvine, CA 92614
949-955-3930

☐ Ashtead Technology Rentals
3311 Preston Avenue
Pasadena, TX 77505
281-991-1448

East Grid NOx

Table 2-1: Final Test and Calibration Values

TEST Values	Observed Value	Units	Nominal Range	Reference Section
RANGE	200	ppm	5-5000	5.3.4
NOISE	.005	ppm	0.0 - 0.2	9.1.1, Table 9-1, 9.2.5
SAMP FLW	285	cc/min	300 ± 50 (Default) 550 ± 50 (Optional)	9.3.7, Table 9-1
OZONE FL	247	cc/min	250 ± 15	9.3.6
PMT	23.1	mV	0-5000	9.3.8
AUTOZERO	47.0	mV	-10 to +50	4.1
HVPS	475	V	400 - 700 constant	9.3.8.5
DCPS	2539	mV	2500 ± 200	9.3.5
RCELL TEMP	50.1	°C	50 ± 2	9.3.8.2
BLOCK TEMP	50.5	°C	50 ± 2	9.3.4.1
BOX TEMP	28.6	°C	8-48	9.3.4.1
PMT TEMP	7.4	°C	7 ± 1	9.3.8.4
CONV TEMP	699.1	°C	700 ± 10 (Std) 315 ± 5 (Moly)	9.3.4.1
RCEL PRES	7.3	IN-Hg-A	2 - 10 constant	9.3.7
SAMP PRES	29.9	IN-Hg-A	25 - 30 constant	9.3.7
		Electric Test & Optic Test		
		Electric Test		
PMT Volts	1994.9	mV	2000 ± 200	9.1.3.2
NO Conc	249.3	ppm	250 ± 25	9.1.3.2
NO_x Conc	249.3	ppm	250 ± 25	9.1.3.2
		OPTIC TEST		
PMT Volts	101.9	mV	100 ± 20	9.1.3.3
NO Conc	12.74	ppm	12.5 ± 2	9.1.3.3
NO_x Conc	12.74	ppm	12.5 ± 2	9.1.3.3

(table continued)

Analog Output = 9.98 @ 100% F.S.

IP10_003386

Table 2-1: Final Test and Calibration Values (Continued)

Parameter	Observed Value	Units	Nominal Range	Reference Section
NO Span Conc	199	ppm	0.5 - 5000	Table 7-3
NO_x Span Conc	199	ppm	0.5 - 5000	Table 7-3
NO Slope	.932	-	1.0 ± 0.3	7.1, 7.9
NO_x Slope	.931	-	1.0 ± 0.3	7.1
NO Offset	0.0	mV	± 25	7.1, 7.2
NO_x Offset	0.0	mV	± 25	7.1, 7.2
Conv Efficiency	94	%	0.75 - 1.10	7.10, 5.2.2.6
Noise at Zero	.005	ppm	0.0 - 0.2	Table 9-1
Noise At Span	.150	ppm	0.1 - 0.5	Table 9-1
Measured Flows				
Sample Flow	290	cc/min	50 ±20	9.3.7, Figure 9-8
Bypass Flow	(total)	cc/min	250 (Std) 500 (Optional)	Figure 8-4
Ozone Flow	—	cc/min	250 ± 15	9.3.7, Figure 9-8

Factory Installed Options	Option Installed
Power Voltage/Frequency	115V/60Hz
Rack Mount, w/ Slides	
Rack Mount, w/ Ears Only	
Rack Mount, External Pump w/o Slides	
Stainless Zero/Span Valves	
4-20 mA Current Loop Output, Isolated	
Bypass flow 500 cc/min	
Molybdenum Converter	
Desiccant Canister - O3 generator	

PROM # 2AAE95TD.1-1 Serial # 335 / R3756

Date 6 Feb 03 Technician D. Stiles

E/W CO Lo range Sample Grid

Model ZRH
INFRARED GAS ANALYZER

DESCRIPTION

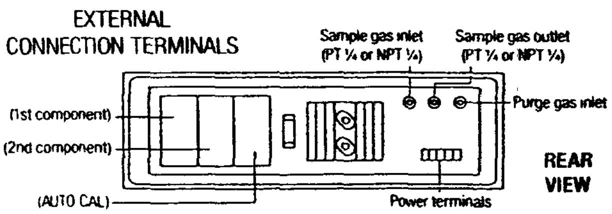
The Model ZRH is a single or dual component non-dispersive infrared (NDIR) gas analyzer used for measuring CO, CO_2 and CH_4 gases. It achieves high accuracy and provides multiple function and ease of operation through the use of a microprocessor. It is available in 19-inch rack, panel or table top mountings.

Zero and span calibrations are easily accomplished by pressing the appropriate key on the front panel.

The ZRH has an improved single beam optical system which provides superior performance to conventional double beam analyzers. It is easy to maintain and offers excellent long term stability. The ZRH is ideal for continuous measurement in the combustion control of burners, incinerators and furnaces as well as CEM-stack systems.

The dual cell type of transmission detector minimizes interferences from other gas components.

The ZRH optical design and modular construction assures long term reliability.



OPTIONS SPECIFICATIONS

REMOTE RANGE CHANGE: Range is changeable via external signal of 5V DC

RANGE IDENTIFICATION SIGNAL OUTPUT:
Contact Type: Form 1A
Contact Rating: 250 VAC, 2A (resistive load)

AUTOMATIC CALIBRATION: Zero and span can be automatically calibrated at a preset cycle.

SPECIFICATIONS

MEASURABLE GAS COMPONENTS: Single-component, multiple range analyzer: CO_2, CO, or CH_4
Two-component multiple range analyzer: CO_2/CO
Ranges: Up to 3 ranges (optional)
200 ppm to 100%
Range ratio–maximum 4 to 1

MEASURING SYSTEM: Nondispersive infrared absorption (NDIR) method, single light source–single beam

OUTPUTS: Analog 4 to 20mA DC, and simultaneous 0 to 1 mV or 0 to 1V or 0 to 5V or 0 to 10VDC selectable
RS-232C

REPEATABILITY:
1st range (low range): Within ±0.5% of full scale
2nd range (high range): Within ±1% of full scale

ZERO DRIFT: Within ±1% of full scale/24 hours

SPAN DRIFT: Within ±1% of full scale/24 hours

RESPONSE TIME: Within 3 seconds, depending on cell length and flow rate

LINEARITY: ±1% of full scale

NOISE: ±0.5% of full scale

POWER SUPPLY: 100, 115, 200 (±10%) VAC, 50/60 Hz

POWER CONSUMPTION: 37VA max.

AMBIENT TEMPERATURE: 23-113°F (−5 to +45°C)

AMBIENT HUMIDITY: Less than 90%RH non-condensing

ENCLOSURE: Steel casing, for indoor use

DISPLAY: 4 digit LED for concentration display
4 digit LED for sub-display

OUTPUT HOLD: Output value can be held during manual or automatic calibration function

MEASURED GAS TEMPERATURE: 32-122°F (0 to 50°C)

WARM-UP TIME: Approximately 1 hour

GAS INLET/OUTLET, PURGE GAS INLET SIZE:
NPT 1/4 Internal thread

MEASURED GAS FLOW RATE: 0.5 to 2 liters/minute

PURGE GAS FLOW RATE: 1 liter/minute

WEIGHT: Approx. 27 lbs. (12 kg)

DIMENSIONS: Rack Mount 5¼"H x 19"W x 17½"D
(133mm x 483mm x 448mm)
Panel Mount 5¼"H x 17½"W x 17½"D
(133mm x 443mm x 448mm)
Table Top 5¾"H x 17½"W x 17½"D
(145mm x 443mm x 448mm)

Specifications subject to change without notice

California Analytical Instruments, Inc.
1238 West Grove Avenue, Orange, California 92665-4134
Telephone: (714) 974-5560 • Fax: (714) 921-2531

Sample Grid O_2 Analyzer

Models 100P and 100F OXYGEN ANALYZERS

DESCRIPTION

CAI offers two oxygen analyzer options:

A. Low cost, reliable galvanic fuel cell (Model 100F)

B. High performance compact paramagnetic sensor (Model 100P)

Both read directly in percent oxygen. Both have multiple ranges and multiple linear outputs. They may be configured as stand-alone analyzers or teamed with our NDIR Series 200 or 300 to deliver a multicomponent solution to your gas analysis requirements. (See our "Configure-your-own" GAS ANALYZERS brochure.)

METHOD OF OPERATION

Paramagnetic

The Model 100P CAI oxygen analyzer measures the paramagnetic susceptibility of the sample gas by means of a magneto-dynamic type measuring cell.

The CAI measuring cell consists of a dumbbell of diamagnetic material, which is temperature controlled electronically at 50°C.

The higher the oxygen concentration, the greater the dumbbell is deflected from its rest position. This deflection is detected by an optical system connected to an amplifier. Surrounding the dumbbell is a coil of wire. A current is passed through this coil to return the dumbbell to its original position. The current applied is linearly proportional to the percent oxygen concentration in the sample gas. This concentration is displayed on a digital panel meter.

Galvanic Fuel Cell

The Model 100F CAI oxygen analyzer utilizes a low cost fuel cell to determine the percent level of oxygen contained in the sample gas. The oxygen level is displayed on a digital panel meter.

SPECIFICATIONS

Model 100P (Paramagnetic Detector)

SAMPLE CONTACT MATERIAL: Platinum, glass, stainless steel, viton

RANGES: Standard fixed ranges, choose A, B or C
- A) Range 1: 0 to 1%, Range 2: 0 to 15%, Range 3: 0 to 25%
- B) Range 1: 0 to 5%, Range 2: 0 to 10%, Range 3: 0 to 25%
- C) Range 1: 0 to 25%, Range 2: 0 to 40%, Range 3: 0 to 100%

RESPONSE TIME: 90% full scale in 2 seconds

WEIGHT: 15 lbs (6.8 kg)

Model 100F (Galvanic Fuel Cell Detector)

SAMPLE CONTACT MATERIAL: Stainless steel and Tygon*

RANGES: Standard fixed ranges, choose A or B
- A) Range 1: 0 to 5%, Range 2: 0 to 10%, Range 3: 0 to 25%
- B) Range 1: 0 to 25%, Range 2: 0 to 40%, Range 3: 0 to 100%

RESPONSE TIME: 90% full scale in 5 seconds

WEIGHT: 10 lbs (4.8 kg)

Common Specifications (Models 100P & 100F)

LINEARITY: Better than 1% full scale

REPEATABILITY: Better than 1% full scale

SAMPLE FLOW RATE: 1 liter/min.

NOISE: Less than 1% full scale

ZERO SPIN DRIFT: Less than 1% full scale in 24 hours

ZERO & SPAN ADJUSTMENT: Ten turn potentiometer

DISPLAY: 3½ digit panel meter

OUTPUTS: 0 to 10 VDC and 4 to 20 mA (0 to 20 mA)

AMBIENT TEMPERATURE: 5 to 45°C

SAMPLE TEMPERATURE: 0 to 50°C

SAMPLE CONDITION: Clean, dry gas

FITTINGS: ¼" tube

POWER REQUIREMENTS: 115/230 (±10%) VAC, 50/60 Hz, 70 watts/channel

RELATIVE HUMIDITY: Less than 90% R.H.**

DIMENSIONS: 5¼"H x 19"W x 15"D (133mmH x 483mmW x 381mmD)

* Tygon is a registered trademark of the Norton Performance Plastics Corporation

** Non-condensing

Specifications subject to change without notice

California Analytical Instruments, Inc.

1238 West Grove Avenue, Orange, California 92865-4134

Telephone: (714) 974-5560 • Fax: (714) 921-2531

Web Site: www.gasanalyzers.com

SPECIFICATIONS

Preset ranges	0-1, 2, 5, 10, 20, 50, 100, 200, 500, 1000, 2000, 5000, 10000 ppm 0-1, 2, 5, 10, 20, 50, 100, 200, 500, 1000, 2000, 5000, 10000 mg/m^3
Custom ranges	0-1 to 10000 ppm 0-1 to 10000 mg/m^3
Zero noise	0.02 ppm RMS (30 second time setting)
Lower detectable limit	0.04 ppm
Zero drift (24 hour)	< 0.1 ppm
Span drift (24 hour)	±1% fullscale
Response time	60 seconds (30 second time setting)
Precision	± 0.1 ppm
Linearity	± 1% fullscale ≤ 1000 ppm ± 2.5% fullscale > 1000 ppm
Sample flow rate	0.5-2 liters/min
Operating temperature	20 - 30°C (may be safely operated over the range of 0 - 45°C)*
Power requirements	105-125 VAC, 60 Hz 220-240 VAC, 50 Hz 100 Watts
Physical dimensions	16.75" (W) X 8.62" (H) X 23" (D)
Weight	45 lbs.
Outputs	CO selectable voltage 4-20 mA, RS-232, RS-485

* In non-condensing environments

TEI 48C CO Analyzer

REFERENCE METHOD DESIGNATION

The Thermo Environmental Instruments, Inc. Model 48C is designated by the United States Environmental Protection Agency (USEPA) as a Reference Method for the measurement of ambient concentrations of Carbon Monoxide pursuant with the requirements defined in the Code of Federal Regulations, Title 40, Part 53.

Designated Reference Method Number: RFCA-0981-054
EPA Designation Date: September 23, 1981

The Model 48C CO Analyzer meets EPA reference designation requirements when operated with the following:

Range	0 - 1 to 100 ppm
Averaging Time	10 to 300 seconds
Temperature Range	20 to 30°C
Line Voltage	90 to 110 VAC @ 50/60 Hertz
	105 to 125 VAC @ 50/60 Hertz
	210 to 250 VAC @ 50/60 Hertz
Pressure Compensation	on or off
Temperature Compensation	on or off
Flow Rate	0.5 to 2 LPM

RS-232 Interface
With or without the following options:

100	Teflon ™ Particulate Filter
200	Carrying Handle
210	Rack Mounts
320	Internal Zero/Span and Sample/Calibration Solenoid Valves
330	Internal Zero/Span and Sample/Calibration Solenoid Valves with Remote I/O Activation
410	Internal Zero Air Scrubber
610	4-20 mA Current Output
725	Remote I/O Board
770	RS-485 Interface

The Model 48C must be operated and maintained according to this Instruction manual to conform to the EPA designation requirements. Any alteration, modification, or republication of this instruction manual or any alteration or modification to the Thermo Environmental Instrument product without the express written consent of Thermo Environmental Instruments Inc. is expressly prohibited, nullifies our warranty obligations, and bars our liability for any damages deriving therefrom.

14.7 General Specifications

Construction

Installing: Standing on its front feet, the recorder can be inclined backwards up to 30 degrees from a horizontal plane.

Dimensions : approx. 152(W) × 225(H) × 240(D) mm

Weight : MV102 : approx. 3.7 kg
MV104 : approx. 3.7 kg
MV106 : approx. 3.8 kg
MV112 : approx. 3.8 kg

Standard Performance

Measuring and Recording Accuracy :

The following specifications apply to operation of the recorder under standard operation conditions :

Temperature : 23 ± 2°C
Humidity : 55% ± 10% RH
Power supply voltage : 90 to 132 or 180 to 250 VAC
Power supply frequency : 50/60 Hz ± 1%
Warm-up time : At least 30 minutes.

Other ambient conditions such as vibration should not adversely affect recorder operation.

Input	Range	Measurement Accuracy (Digital Display)	Max. Resolution of Digital Display
DC voltage	20 mV	± (0.1% of rdg + 2 digits)	10 µV
	60 mV		10 µV
	200 mV		100 µV
	2 V		1 mV
	6 V		1 mV
	20 V		10 mV
TC (Excluding the reference junction compensation accuracy)	R	± (0.15% of rdg + 1°C) However, R, S : ± 3.7°C at 0 to 100°C, ± 1.5°C at 100 to 300°C B : ± 2°C at 400 to 600°C (Accuracy at less than 400°C is not guaranteed.)	0.1°C
	S		
	B		
	K	± (0.15% of rdg + 0.7°C) However, ± (0.15% of rdg + 1°C) at −200 to −100°C	
	E	± (0.15% of rdg + 0.5°C)	
	J	± (0.15% of rdg + 0.5°C) However, ± (0.15% of rdg + 0.7°C) at −200 to −100°C	
	T		
	N	± (0.15% of rdg + 0.7°C)	
	W	± (0.15% of rdg + 1°C)	
	L	± (0.15% of rdg + 0.5°C) However, ± (0.15% of rdg + 0.7°C) at −200 to −100°C	
	U		
RTD	Pt100	± (0.15% of rdg + 0.3°C)	
	JPt100		

Measuring accuracy in case of scaling (digits) :

Accuracy during scaling (digits) =
measuring accuracy (digits) × multiplier + 2 digits (rounded up)

where the multiplier = scaling span (digits)/measuring span (digits).

Example : Assuming that

- range : 6 V
- measuring span : 1.000 to 5.000 V
- scaling span : 0.000 to 2.000

Then,
Measuring accuracy = ±(0.1% × 5 V + 2 digits)
= ±(0.005 V [5 digits] + 2)
= ±(7 digits)

Multiplier = 2000 digits (0.000 to 2.000)/4000 digits (1.000 to 5.000 V) = 0.5

Accuracy during scaling = 7 digits × 0.5 + 2 = 6 digits (rounded up)

Reference junction compensation :
Internal/External selectable for each channel

Reference junction compensation accuracy (above 0°C) :
Types R, S, B, W : ±1°C
Types K, J, E, T, N, L, U : ±0.5°C

Maximum allowable input voltage :
±10 V DC (continuous) for ranges of 2 V or less and TC ranges
±30 V DC (continuous) for 6 V DC and 20 V DC ranges

Input resistance :
Approximately 10 MΩ or more for ranges of 2 V DC or less and TC
Approximately 1 MΩ for 6 V DC and 20 V DC ranges

Input source resistance :
Volt, TC : 2 kΩ or less
RTD : 10 Ω or less per wire (The resistance of all three wires must be equal).

Input bias current : 10 nA or less

Maximum common mode noise voltage :
250 Vrms AC (50/60 Hz)

Maximum noise voltage between channels :
250 Vrms AC (50/60 Hz)

Interference between channels :
120 dB (when the input source resistance is 500 Ω and the inputs to other channels are 30 V)

Common mode rejection ratio :
120 dB (50/60 Hz ±0.1%, 500 Ω imbalance, between the minus terminal and ground)

Normal mode rejection ratio :
40 dB (50/60 Hz ±0.1%)

Stack CO

ASHTEAD Technology RENTALS

Calibration Certificate

Equipment Information:

CUSTOMER: Environmental Systems Corp
INSTRUMENT: API CO Analyzer
MODEL: 300
SERIAL #: 194 / R3827

Calibration Standards:

STANDARD:	ZeroAir #314-05695	RESPONSE:	0.0 ppm
STANDARD:	105.9 ppm CO #089060-00	RESPONSE:	106.1 ppm
STANDARD:	______	RESPONSE:	______
STANDARD:	______	RESPONSE:	______

TECHNICIAN: D. Stiles
DATE: 5 February 2003
DUE DATE: N/A

NOTES:
Unit performs within specifications:__X___, Flow OK:__X___.
_______Slope: 0.939, Offset 0.062______

This instrument has been calibrated according to the calibration procedure as described in the operation manual.

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1057 East Henrietta Road
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18195 McDurmott East, Suite A/B
Irvine, CA 92614
949-955-3930

☐Ashtead Technology Rentals
3311 Preston Avenue
Pasadena, TX 77505
281-991-1448

FINAL TEST AND CALIBRATION VALUES

TEST VALUES		
RANGE	1000	PPM
CO MEAS	4448.5	~~mV~~
CO REF	3764.9	~~mV~~
MR RATIO	1.192	
SAMPLE PRESS	29.6	IN HG-A
SAMPLE FLOW	888	SCC/MIN
SAMPLE TEMP	49	C
OPTICAL BENCH TEMP	48	C
Mirror ~~WHEEL~~ TEMP	48	C
BOX TEMP	21	C
DC POWER SUPPLY	2470	mV
TIME	17:43	HH:MM:SS

INSTALLED OPTIONS	
ZERO-SPAN VALVES	☐
RACK MOUNTS/SLIDES	☐
POWER 115/60 VOLTS/Hz	
4-20mA OUTPUT	☐
IZS	☐
OTHER ______	☐

CALIBRATION VALUES		
CO SPAN SETTING	______	PPM
CO ZERO SETTING	______	PPM
CO SLOPE	.939	
CO OFFSET	.0622	

SETUP VALUES		
ELECTRIC TEST	37.7	PPM
DARK MEAS	112.0	mV
DARK REF	111.9	mV

Analog Output = 10.01 V @ 100% F.S.

CONFIGURATION DATA	
PROM REV ______	ANALYZER SERIAL # 194/R3827

TECHNICIAN D. Stiles DATE 5 Feb 03

TABLE 1.1

41

INTERMOUNTAIN POWER SERVICE CORPORATION

Feeder ID: 1FDR-1A

Coal Feedrate Meter Calibration Report

---

sign Capacities:

Design Load: 39.03 PPF

Design Feedrate: 136,000 PPH

Design Belt Speed: 58.09 FPM

Test Chain Calibration Weight: 34.849

Belt Parameters:

Belt Length:

Pulses Per Belt Rev: 6335.2

No. Calibration Revs: 5

No. Speed Calibration Revs: 5

CALIBRATION PROCEDURES

1. Record Grand Total Reading: 6359.4 TN

2. Switch to Calibration Mode: Select MC3 Feeder Control Mode to "MANUAL" indicating.

3. Speed Calibration:

Initial Pulses/Rev. = 6388

Old Pulse/Rev. = 6359.4

Pulse/Rev. = 6335.2

4. Zeroing Procedure:

Initial Zero Load = 60.20

Difference =

Old Zero Load = 64.87 lb/ft

New Zero Load = 64.30 lb/ft

5. Chain Procedure:

Initial Scale Factore =

Difference =

Old Scale Factor = 5401.708

New Scale Factor = 5465.67

6. Return Feeder to Normal

Reset all 'TOTALS' by pressing the 'ACT' button and following menu steps

Return MC3 'FEEDER CONTROL' mode to 'AUTO' and 'REM ANA' indicating

Return Feeder Cabinet Switch 'GRAV/MAN-CAL/VOL' to 'GRAV' position

Verify Feeder Cabinet Switch 'LOCAL/OFF/AUTO' is in 'AUTO' position

Comments: ______________________________

____

____

Date: 8/20/2003

Technician: CowleyM

INTERMOUNTAIN POWER SERVICE CORPORATION

Feeder ID: 1FDR-1B

Coal Feedrate Meter Calibration Report

Design Capacities:

Design Load: 39.03 PPF

Design Feedrate: 136,000 PPH

Design Belt Speed: 58.09 FPM

Test Chain Calibration Weight: 34.849

Belt Parameters:

Belt Length:

Pulses Per Belt Rev: 6400

No. Calibration Revs:

No. Speed Calibration Revs:

CALIBRATION PROCEDURES

1. **Record Grand Total Reading:** 135100 TN

2. **Switch to Calibration Mode:** Select MC3 Feeder Control Mode to "MANUAL" indicating.

3. **Speed Calibration:**

Initial Pulses/Rev. =

Old Pulse/Rev. = 6335

New Pulse/Rev. = 6400

4. **Zeroing Procedure:**

Initial Zero Load =

Difference = -0.11 %

Old Zero Load = 61.51 lb/ft

New Zero Load = 61.46 lb/ft

5. **Chain Procedure:**

Initial Scale Factore =

Difference = 0.230 %

Old Scale Factor = 5479.819

New Scale Factor = 5493.95

6. **Return Feeder to Normal**

Reset all 'TOTALS' by pressing the 'ACT' button and following menu steps

Return MC3 'FEEDER CONTROL' mode to 'AUTO' and 'REM ANA' indicating

Return Feeder Cabinet Switch 'GRAV/MAN-CAL/VOL' to 'GRAV' position

Verify Feeder Cabinet Switch 'LOCAL/OFF/AUTO' is in 'AUTO' position

Comments: ______________________________

____

____

____

Date: 8/19/2003

Technician: Mork

INTERMOUNTAIN POWER SERVICE CORPORATION

Feeder ID: 1FDR-1C   Coal Feedrate Meter Calibration Report

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ign Capacities:

Design Load: 39.03 PPF

Design Feedrate: 68.00 TN/H

Design Belt Speed: 58.09 FPM

Test Chain Calibration Weight: 34.849

Belt Parameters:

Belt Length:

Pulses Per Belt Rev: 6352.2

No. Calibration Revs: 5

No. Speed Calibration Revs: 5

CALIBRATION PROCEDURES

1. **Record Grand Total Reading:** 57587 TN

2. **Switch to Calibration Mode:** Select MC3 Feeder Control Mode to "MANUAL" indicating.

3. **Speed Calibration:**

Initial Pulses/Rev. = 6394

Old Pulse/Rev. = 6340.2

Pulse/Rev. = 6352.2

4. **Zeroing Procedure:**

Initial Zero Load = 60.97

Difference = -0.76 %

Old Zero Load = 53.14 lb/ft

New Zero Load = 52.84 lb/ft

5. **Chain Procedure:**

Initial Scale Factore = 5337.0000

Difference = 0.210 %

Old Scale Factor = 5308.3491

New Scale Factor = 5320.8091

6. **Return Feeder to Normal**

Reset all 'TOTALS' by pressing the 'ACT' button and following menu steps

Return MC3 'FEEDER CONTROL' mode to 'AUTO' and 'REM ANA' indicating

Return Feeder Cabinet Switch 'GRAV/MAN-CAL/VOL' to 'GRAV' position

Verify Feeder Cabinet Switch 'LOCAL/OFF/AUTO' is in 'AUTO' position

Comments: ______________________________

Date: 8/15/2003   **Technician:** Mork

INTERMOUNTAIN POWER SERVICE CORPORATION

Feeder ID: 1FDR-1D — Coal Feedrate Meter Calibration Report

Design Capacities:	**Belt Parameters:**
Design Load: 39.03 PPF	**Belt Length:**
Design Feedrate: 68.00 TN/H	**Pulses Per Belt Rev:** 6352
Design Belt Speed: 58.09 FPM	**No. Calibration Revs:** 5
Test Chain Calibration Weight: 34.849	**No. Speed Calibration Revs:** 5

CALIBRATION PROCEDURES

1. **Record Grand Total Reading:** 154383 TN

2. **Switch to Calibration Mode:** Select MC3 Feeder Control Mode to "MANUAL" indicating.

3. **Speed Calibration:**	4. **Zeroing Procedure:**	5. **Chain Procedure:**
Initial Pulses/Rev. = 6370	Initial Zero Load = 60.97	Initial Scale Factore = 5403.0122
Old Pulse/Rev. = 6347.8	Difference =	Difference =
New Pulse/Rev. = 6352	Old Zero Load = 57.82 lb/ft	Old Scale Factor = 5346.692
	New Zero Load = 59.36 lb/ft	New Scale Factor = 5313.613

6. **Return Feeder to Normal**

Reset all 'TOTALS' by pressing the 'ACT' button and following menu steps

Return MC3 'FEEDER CONTROL' mode to 'AUTO' and 'REM ANA' indicating

Return Feeder Cabinet Switch 'GRAV/MAN-CAL/VOL' to 'GRAV' position

Verify Feeder Cabinet Switch 'LOCAL/OFF/AUTO' is in 'AUTO' position

Comments: ______________________________

Date: 8/15/2003 **Technician:** CowleyM

INTERMOUNTAIN POWER SERVICE CORPORATION

Feeder ID: 1FDR-1E

Coal Feedrate Meter Calibration Report

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ign Capacities:

Design Load: 39.03 PPF

Design Feedrate: 136,000 PPH

Design Belt Speed: 58.09 FPM

Test Chain Calibration Weight: 34.849

Belt Parameters:

Belt Length:

Pulses Per Belt Rev: 6320.6

No. Calibration Revs: 5

No. Speed Calibration Revs: 5

CALIBRATION PROCEDURES

1. Record Grand Total Reading: 102470 TN

2. Switch to Calibration Mode: Select MC3 Feeder Control Mode to "MANUAL" indicating.

3. Speed Calibration:

Initial Pulses/Rev. = 6361.4

Old Pulse/Rev. = 6315.4

Pulse/Rev. = 6320.6

4. Zeroing Procedure:

Initial Zero Load = 56.89

Difference =

Old Zero Load = 42.70 lb/ft

New Zero Load = 44.15 lb/ft

5. Chain Procedure:

Initial Scale Factore = 5469.8247

Difference =

Old Scale Factor = 8217.06

New Scale Factor = 8085.71

6. Return Feeder to Normal

Reset all 'TOTALS' by pressing the 'ACT' button and following menu steps

Return MC3 'FEEDER CONTROL' mode to 'AUTO' and 'REM ANA' indicating

Return Feeder Cabinet Switch 'GRAV/MAN-CAL/VOL' to 'GRAV' position

Verify Feeder Cabinet Switch 'LOCAL/OFF/AUTO' is in 'AUTO' position

Comments:

Date: 8/5/2003

Technician: CowleyM

INTERMOUNTAIN POWER SERVICE CORPORATION

Feeder ID: 1FDR-1G

Coal Feedrate Meter Calibration Report

Design Capacities:

Design Load: 39.03 PPF

Design Feedrate: 68.00 TN/H

Design Belt Speed: 58.09 FPM

Test Chain Calibration Weight: 34.849

Belt Parameters:

Belt Length:

Pulses Per Belt Rev:

No. Calibration Revs: 5

No. Speed Calibration Revs: 5

CALIBRATION PROCEDURES

1. **Record Grand Total Reading:** 402618 TN

2. **Switch to Calibration Mode:** Select MC3 Feeder Control Mode to "MANUAL" indicating.

3. Speed Calibration:

Initial Pulses/Rev. = 6386

Old Pulse/Rev. =

New Pulse/Rev. =

4. Zeroing Procedure:

Initial Zero Load = 54.24

Difference = 1.01 %

Old Zero Load = 58.29 lb/ft

New Zero Load = 58.69 lb/ft

5. Chain Procedure:

Initial Scale Factore = 5492.8652

Difference = 0.957 %

Old Scale Factor = 5458.4409

New Scale Factor = 5516.9233

6. Return Feeder to Normal

Reset all 'TOTALS' by pressing the 'ACT' button and following menu steps

Return MC3 'FEEDER CONTROL' mode to 'AUTO' and 'REM ANA' indicating

Return Feeder Cabinet Switch 'GRAV/MAN-CAL/VOL' to 'GRAV' position

Verify Feeder Cabinet Switch 'LOCAL/OFF/AUTO' is in 'AUTO' position

Comments:

Date: 8/13/2003

Technician: Kelsey

INTERMOUNTAIN POWER SERVICE CORPORATION

Feeder ID: 1FDR-1H

Coal Feedrate Meter Calibration Report

Design Capacities:

Design Load: 39.03 PPF

Design Feedrate: 136,000 PPH

Design Belt Speed: 58.09 FPM

Test Chain Calibration Weight: 34.849

Belt Parameters:

Belt Length:

Pulses Per Belt Rev: 6326.4

No. Calibration Revs:

No. Speed Calibration Revs:

CALIBRATION PROCEDURES

1. Record Grand Total Reading: 93963 TN

2. Switch to Calibration Mode: Select MC3 Feeder Control Mode to "MANUAL" indicating.

3. Speed Calibration:

Initial Pulses/Rev. =

Old Pulse/Rev. = 6335.4

New Pulse/Rev. = 6326.4

4. Zeroing Procedure:

Initial Zero Load =

Difference = 1.02 %

Old Zero Load = 64.24 lb/ft

New Zero Load = 64.64 lb/ft

5. Chain Procedure:

Initial Scale Factore =

Difference = -0.768 %

Old Scale Factor = 5452.65

New Scale Factor = 5405.75

6. Return Feeder to Normal

Reset all 'TOTALS' by pressing the 'ACT' button and following menu steps

Return MC3 'FEEDER CONTROL' mode to 'AUTO' and 'REM ANA' indicating

Return Feeder Cabinet Switch 'GRAV/MAN-CAL/VOL' to 'GRAV' position

Verify Feeder Cabinet Switch 'LOCAL/OFF/AUTO' is in 'AUTO' position

Comments:

Date: 8/17/2003

Technician: Sorensen

Boiler O2 Calibration Report

Cal Data:

Unit 1

Date 9/18/2003

Technician R.KELSEY

Time 3:45:00 PM

Zero Gas Value 0.4

Span Gas Value 8

	East				West			
Probe: (E to W)	1	2	3	4	5	6	7	8
As Found Instrument O2:	3.73	1.97	1.16	2.51	2.27	4.62	1.65	3.38
	Average East (A Duct)	2.34			Average West (B Duct)	2.98		
Purge? (Y/N)	Y	Y	Y	Y	Y	Y	Y	Y
Zero Flow Rate:	1	1	1	1	1	1	1	1
mV Zero:	91.7	94.17	84.45	86.76	92.47	89.52	80.4	90.6
Instrument O2:	0.42	0.19	0.2	0.36	0.41	0.44	0.3	0.42
Span Flow Rate:	1	1	1	1	1	1	1	1
mV Span:	22.735	24.22	23.02	24.73	22.574	21.628	23.5	21.46
Instrument O2:	8.27	4.46	3.53	5.65	9.1	8.45	3.87	8.14
Probe Temp:	803	800	801	801	800	802	801	802
Upon cal. completion and stable meter reading, please record O2 concentrations for each probe & pass:								
Instrument O2:	3.12	3.57	2.97	2.03	3.13	4.7	3.43	3.52
	Average East (A Duct)	2.52			Average West (B Duct)	3.23		

Comments:

BOILER- OVERFIRE AIR/ BURNER TESTING

Results of IGS Unit 1 OFA Test Series 9/6-9/2003 @ 950 MWg

Data Sorted by OFA flow, then O2%			OFA RATIO 1COAXI172B %	ECON OUT O2 1COAXI187A %	O2 Average test grid %	Stack CO- corr test PPM	NOx lb/mbtu CEM lb/mbtu
No Overfire Air (5% leakage)							
Test # 16 (Day4-T1)	9/9/03 Tue	7:30	4.7	3.2	4.2	13	0.413
Test # 1 (Day1-T1)	9/6/03 Sat	8:15	5.3	3.1	3.9	2.3	0.529
Test # 6 (Day2-T1)	9/7/03 Sun	7:45	4.9	2.6	3.2	41	0.418
Test # 12 (Day3-T2)	9/8/03 Mon	10:30	4.5	2.1	2.6	240	0.377
Test # 13 (Day3-T3)	9/8/03 Mon	12:30	4.7	1.7	2.0	696	0.350
10% Overfire Air (1/3 dampers open)							
Test # 15 (Day3-T5)	9/8/03 Mon	16:15	8.4	3.3	4.2	3	0.399
Test # 2 (Day1-T2)	9/6/03 Sat	10:15	10.8	3.0	3.5	22	0.438
Test # 7 (Day2-T2)	9/7/03 Sun	9:45	8.8	2.5	3.1	54	0.378
Test # 11 (Day3-T1)	9/8/03 Mon	8:15	9.0	1.9	2.7	242	0.327
Test # 14 (Day3-T4)	9/8/03 Mon	14:30	8.1	1.7	2.0	899	0.306
12% Overfire Air (2/3 dampers throttled)							
Test # 4 (Day1-T4)	9/6/03 Sat	14:15	11.9	3.0	3.5	20	0.417
Test # 18a (Day4-T3)	9/9/03 Tue	14:15	11.3	2.7	3.7	161	0.382
Test # 5 (Day1-T5)	9/6/03 Sat	15:45	12.0	2.5	3.0	169	0.382
Test # 10 (Day2-T5)	9/7/03 Sun	17:00	8.7	1.9	2.5	212	0.342
14% Overfire Air (2/3 dampers open)							
Test # 17 (Day4-T2)	9/9/03 Tue	9:45	11.3	3.8	4.6	33	0.375
Test # 3 (Day1-T3)	9/6/03 Sat	12:30	14.5	2.7	3.4	43	0.377
Test # 8 (Day2-T3)	9/7/03 Sun	13:05	12.7	2.4	3.2	50	0.359
Test # 9 (Day2-T4)	9/7/03 Sun	15:15	12.6	2.0	2.6	302	0.314

BOILER- OVERFIRE AIR/ BURNER TESTING

Results of IGS Unit 1 OFA Test Series 9/6-9/2003 @ 950 MWg

Data Sorted by O2%, then OFA flow			OFA RATIO 1COAXI172B %	ECON OUT O2 1COAXI187A %	O2 Average test grid %	Stack CO- corr test PPM	NOx lb/mbtu CEM lb/mbtu
Target 3.5 O2% control room							
Test # 16 (Day4-T1)	9/9/03 Tue	7:30	4.7	3.2	4.2	13	0.413
Test # 15 (Day3-T5)	9/8/03 Mon	16:15	8.4	3.3	4.2	3	0.399
Test # 17 (Day4-T2)	9/9/03 Tue	9:45	11.3	3.8	4.6	33	0.375
Target 3.0 O2% control room							
Test # 1 (Day1-T1)	9/6/03 Sat	8:15	5.3	3.1	3.9	2.3	0.529
Test # 2 (Day1-T2)	9/6/03 Sat	10:15	10.8	3.0	3.5	22	0.438
Test # 18a (Day4-T3)	9/9/03 Tue	14:15	11.3	2.7	3.7	161	0.382
Test # 4 (Day1-T4)	9/6/03 Sat	14:15	11.9	3.0	3.5	20	0.417
Test # 3 (Day1-T3)	9/6/03 Sat	12:30	14.5	2.7	3.4	43	0.377
Target 2.5 O2% control room							
Test # 6 (Day2-T1)	9/7/03 Sun	7:45	4.9	2.6	3.2	41	0.418
Test # 7 (Day2-T2)	9/7/03 Sun	9:45	8.8	2.5	3.1	54	0.378
Test # 5 (Day1-T5)	9/6/03 Sat	15:45	12.0	2.5	3.0	169	0.382
Test # 8 (Day2-T3)	9/7/03 Sun	13:05	12.7	2.4	3.2	50	0.359
Target 2.0 O2% control room							
Test # 12 (Day3-T2)	9/8/03 Mon	10:30	4.5	2.1	2.6	240	0.377
Test # 10 (Day2-T5)	9/7/03 Sun	17:00	8.7	1.9	2.5	212	0.342
Test # 11 (Day3-T1)	9/8/03 Mon	8:15	9.0	1.9	2.7	242	0.327
Test # 9 (Day2-T4)	9/7/03 Sun	15:15	12.6	2.0	2.6	302	0.314
Target 1.5 O2% control room							
Test # 13 (Day3-T3)	9/8/03 Mon	12:30	4.7	1.7	2.0	696	0.350
Test # 14 (Day3-T4)	9/8/03 Mon	14:30	8.1	1.7	2.0	899	0.306

BOILER- OVERFIRE AIR/ BURNER TESTI TEST SERIES for STATE of UTAH, September 6- 9, 2003

NOTE: Master data download file and calculation spreadsheet. Insert ALL data and calcs here (in this spreadsheet) and then reference (copy) cells to other spreadsheets, graphs, etc. Reason-

PARAMETER	PT ID	UNITS	Test # 1 (Day1-T1) 9/6/03 Sat 8:15 9:30	Test # 2 (Day1-T2) 9/6/03 Sat 10:15 11:30	Test # 3 (Day1-T3) 9/6/03 Sat 12:30 13:30	Test # 4 (Day1-T4) 9/6/03 Sat 14:15 15:30	Test # 5 (Day1-T5) 9/6/03 Sat 15:45 16:45	Test # 6 (Day2-T1) 9/7/03 Sun 7:45 9:00	Test # 7 (Day2-T2) 9/7/03 Sun 9:45 10:45	Test # 8 (Day2-T3) 9/7/03 Sun 13:05 14:05
[redacted]I)										
UNIT LOAD	1COAXI027A	MW	950.0	952.6	950.8	949.6	949.5	952.4	952.4	949.1
TURBINE THROTTLE PRE	1COAXI012A	psig	2402.5	2402.9	2403.1	2401.4	2403.5	2406.5	2406.8	2407.1
THROTTLE TEMP	1COAXI015A	°F	1003.7	1001.0	1006.3	994.2	1004.9	1004.1	1004.7	1004.9
TURBINE STEAM FLOW	1COAXI024	kpph	6808.2	6846.6	6807.2	6828.3	6847.8	6781.2	6804.8	6755.6
STEAM FLOW (FW + SSF)	1COAXI023A	kpph	6794.3	6852.2	6779.2	6855.7	6849.9	6753.1	6776.6	6726.7
FDW FLOW TO ECONOMI	1COAXI021A	kpph	6720.4	6796.6	6631.5	6801.6	6780.1	6582.0	6623.2	6566.8
TOTAL COAL FLOW	1COAXI001B	tph	345.2	343.8	343.5	343.1	342.6	370.7	375.3	377.3
TOTAL FUEL FLOW	1COAXI001A	tph	345.9	344.0	344.2	342.7	343.2	370.9	375.4	377.9
TOTAL AIR FLOW	1COAXI078S	%	86.9	86.0	86.2	85.5	82.5	81.7	83.8	85.0
EAST FLUE GAS O2	1COAXI079A	%	2.9	2.7	2.1	2.8	2.5	2.3	2.0	2.2
WEST FLUE GAS O2	1COAXI080A	%	3.4	3.2	3.4	3.2	2.5	3.0	3.0	2.7
EAST FLUE GAS COMB	1COAXI081A	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OVERFIRE AIR										
OFA SW 1/3 DMPR P	1SGBKS164B	%	0.6	55.4	1.5	1.2	1.0	1.4	56.4	0.9
OFA SE 1/3 DMPR P	1SGBKS166B	%	2.0	55.4	2.0	2.0	2.0	2.6	56.8	2.4
OFA NW 1/3 DMPR P	1SGBKS168B	%	0.0	88.8	0.6	0.4	0.3	0.0	67.1	0.0
OFA NE 1/3 DMPR P	1SGBKS170B	%	6.3	99.2	6.0	6.1	6.2	6.1	99.1	5.9
OFA SW 2/3 DMPR P	1SGBKS165B	%	0.0	0.0	58.8	43.1	43.0	0.0	0.0	59.2
OFA SE 2/3 DMPR P	1SGBKS167B	%	0.0	0.0	51.7	43.7	43.6	0.5	0.2	55.6
OFA NW 2/3 DMPR P	1SGBKS169B	%	0.4	0.7	56.8	46.5	46.5	0.0	0.0	58.2
OFA NE 2/3 DMPR P	1SGBKS171B	%	0.3	0.7	98.9	61.4	61.6	0.3	0.3	98.4
OFA SW INLET DMPR P	1SGBKS156B	%	0.0	99.3	99.4	99.5	98.5	0.0	99.6	99.2
OFA SE INLET DMPR P	1SGBKS158B	%	0.0	99.3	99.1	99.0	98.9	0.0	99.2	99.0
OFA NW INLET DMPR P	1SGBKS160B	%	0.5	98.1	97.9	97.8	97.7	0.0	98.1	97.8
OFA NE INLET DMPR P	1SGBKS162B	%	0.5	99.4	99.2	98.9	98.8	0.0	98.6	98.6
OFA TO TOTAL AIR RATIO	1COAXI172B	%	5.3	10.8	14.5	11.9	12.0	4.9	8.8	12.7
SW OFA FLOW	1SGBFT0155	KPPH	135.2	198.8	265.8	216.1	207.7	127.9	175.4	252.6
SE OFA FLOW	1SGBFT0156	KPPH	113.4	200.8	259.7	218.9	208.3	103.9	160.4	237.6
NW OFA FLOW	1SGBFT0157	KPPH	60.0	192.8	264.6	226.0	217.1	53.9	185.4	253.7
NE OFA FLOW	1SGBFT0158	KPPH	80.2	189.5	255.1	220.9	214.7	75.3	173.7	241.7
TOTAL OFA AIR	1COAXI172C	KPPH	388.7	782.3	1044.4	883.0	849.2	362.6	694.9	987.3
[redacted]										
West Side O2		%	3.79	3.32	3.82	3.48	2.58	3.20	3.35	3.21
East Side O2		%	3.92	3.73	3.07	3.57	3.36	3.10	2.90	3.25
O2 Average		%	3.86	3.53	3.44	3.53	2.97	3.15	3.12	3.23
West Side CO2		%	14.11	14.36	13.88	14.04	14.67	15.91	15.70	15.62
East Side CO2		%	14.80	14.76	15.27	14.86	14.92	15.89	16.00	15.39

BOILER- OVERFIRE AIR/ BURNER TESTIN TEST SERIES for STATE of UTAH, September 6- 9, 2003

NOTE: Master data download file and calculation spreadsheet. Insert ALL data and calcs here (in this spreadsheet) and then reference (copy) cells to other spreadsheets, graphs, etc. Reason-

PARAMETER	PT ID	UNITS	Test # 1 (Day1-T1) 9/6/03 Sat 8:15 9:30	Test # 2 (Day1-T2) 9/6/03 Sat 10:15 11:30	Test # 3 (Day1-T3) 9/6/03 Sat 12:30 13:30	Test # 4 (Day1-T4) 9/6/03 Sat 14:15 15:30	Test # 5 (Day1-T5) 9/6/03 Sat 15:45 16:45	Test # 6 (Day2-T1) 9/7/03 Sun 7:45 9:00	Test # 7 (Day2-T2) 9/7/03 Sun 9:45 10:45	Test # 8 (Day2-T3) 9/7/03 Sun 13:05 14:05
CO2 Average		%	14.46	14.56	14.57	14.45	14.80	15.90	15.85	15.50
West Side NOx		PPM	274.10	251.11	222.45	285.62	294.03	232.27	217.05	263.20
East Side NOx		PPM	337.94	323.71	303.20	194.18	156.21	201.85	224.01	281.74
NOx Average		PPM	306.02	287.41	262.83	239.90	225.12	217.06	220.53	272.47
Low Range CO Analyzer West Side		PPM	6.2	24.5	27.6	13.4	103.0	63.3	11.6	82.8
Low Range CO Analyzer East Side		PPM	4.7	28.9	90.4	25.4	80.0	32.8	129.8	71.5
Low Range CO Analyzer Average		PPM	5.4	26.7	59.0	19.4	91.5	48.0	70.7	77.2
High Range CO Analyzer West Side		PPM	1.6	22.5	26.2	13.6	107.8	63.1	9.5	85.2
High Range CO Analyzer East Side		PPM	0.0	31.1	99.8	26.0	88.1	33.0	140.0	80.9
High Range CO Analyzer Average		PPM	0.8	26.8	63.0	19.8	98.0	48.0	74.7	83.1
Stack CO		PPM	2.6	24.8	49.2	22.8	194.1	47.4	62.4	57.3
Stack CO- corrected	calc- measurem	PPM	2.3	21.7	43.1	20.0	169.4	41.2	54.4	50.0
CO converted #/mbtu	calc	#/mbtu	0.002	0.018	0.035	0.017	0.137	0.033	0.044	0.040
CO converted #/hr	calc	#/hr	23	213	422	196	1617	395	525	490
[illegible]										
CO2		%	12.25	12.46	12.42	12.41	12.73	12.98	12.87	12.75
NOx PPM		PPM	302	254	218	241	226	252	227	213
NOx lb/mbtu		lb/mbtu	0.529	0.438	0.377	0.417	0.382	0.418	0.378	0.359
Stack Flow		scfh	136,991,091	135,130,550	135,058,216	135,393,230	131,594,456	132,053,502	133,235,524	135,267,312
CALCS										
Excess Air @ furn	calc	%	9.7	4.4	1.1	3.9	3.5	8.2	3.3	-2.4
Diff O2 CR- O2 grid	*calc*	%	-0.72	-0.57	-0.70	-0.57	-0.46	-0.50	-0.63	-0.81
NOX Reduction (#/mbtu), s	calc	%	base	20.8	40.3	26.9	9.4	base	10.6	16.4
NOX Reduction (#/mbtu), v	calc	%	base	20.8	40.3	26.9	38.5	26.6	39.9	47.4
CO Increase (ppm), same C	calc	%	base	89.5	94.7	88.6	75.6	base	24.1	17.5
			base	89.5	94.7	88.6	75.6	base	24.1	17.5
CO Increase (ppm), max ba	calc	%	base	89.5	0.0	-107.1	1.0	-358.0	-35.9	-65.3
CO Increase (#/mbtu)	calc	%	base	89.4	94.6	88.5	75.5	base	23.5	16.5
[illegible]										
HHV		Btu/lb	12540	12652	12639	12716	12688	12183	11782	11736
MAF HHV		Btu/lb	14485	14588	14628	14616	14626	14485	14273	14250
% MOISTURE		%	6.29	6.44	6.73	6.44	6.69	8.01	8.54	9.09
% ASH		%	7.14	6.83	6.87	6.56	6.56	7.88	8.91	8.55
% SULFUR		%	0.52	0.54	0.59	0.57	0.58	0.54	0.53	0.53
% CARBON		%	70.14	70.35	70.04	70.37	70.38	67.61	65.91	65.82
% HYDROGEN		%	4.72	4.68	4.77	4.75	4.77	4.55	4.37	4.41
% NITROGEN		%	1.61	1.59	1.6	1.63	1.6	1.48	1.42	1.44

BOILER- OVERFIRE AIR/ BURNER TESTI TEST SERIES for STATE of UTAH, September 6- 9, 2003

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% OXYGEN		%	9.58	9.57	9.4	9.68	9.42	9.93	10.32	10.16
COAL..AS-FIRED										
HHVC	9CHEKT0001	BTU/LB	12220.1	12220.1	12220.1	12220.1	12220.1	12663.0	12663.0	12663.0
% TOTAL MOISTURE	9CHEKT0005	%	4.3	4.3	4.3	4.3	4.3	4.5	4.5	4.5
% ASH	9CHEKT0006	%	10.6	10.6	10.6	10.6	10.6	8.7	8.7	8.7
% SULFUR	9CHEKT0007	%	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7
% CARBON	9CHEKT0009	%	68.6	68.6	68.6	68.6	68.6	70.4	70.4	70.4
% HYDROGEN	9CHEKT0010	%	4.4	4.4	4.4	4.4	4.4	4.6	4.6	4.6
% NITROGEN	9CHEKT0011	%	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
% OXYGEN	9CHEKT0012	%	9.9	9.9	9.9	9.9	9.9	9.4	9.4	9.4
[redacted]										
LOI AVE (IPSC)	CALC	%	2.54	1.58	2.11	2.16	2.53	1.83	1.12	1.41
LOI EAST (IPSC)	MANUAL	%	2.97	1.45	2.37	2.67	3.00	2.52	1.41	1.76
LOI WEST (IPSC)	MANUAL	%	2.11	1.71	1.85	1.65	2.06	1.14	0.82	1.06
AEA EAST	MANUAL		47	50	50	61	55	46	39	47
AEA WEST	MANUAL		31	33	22	28	30	29	25	31
COLOR EAST	MANUAL		411	511	511	411	411	411	511	411
COLOR WEST	MANUAL		512	512	611	511	512	611	611	512
[redacted]) continued										
UNIT										
GROSS CAPACITY	1COAXI027A	MW	950.0	952.6	950.8	949.6	949.5	952.4	952.4	949.1
AUXILIARY POWER	1APEPE0005	MW	55.5	55.0	55.9	56.6	54.7	53.2	53.6	55.4
GROSS UNIT HEAT RATE	CALC	BTU/KWH								
NET UNIT HEAT RATE I/O	CALC	BTU/KWH								
% AUX POWER	CALC	%								
STEAM TURBINE										
CORR GROSS CAPACITY	CALC	MW								
NET TURBINE HEAT RATE	CALC	BTU/KWH								
CYCLE LOSSES	CALC	KPPH								
THROTTLE FLOW	CALC	KPPH								
FEEDWATER FLOW	1COAXI021A	KPPH	6720.4	6796.6	6631.5	6801.6	6780.1	6582.0	6623.2	6566.8
CORR THROTTLE FLOW	CALC	KPPH								
ECONOMIZER INLET TEM	1COAXI025A	DEGF	548.0	548.2	548.4	547.7	548.1	548.6	548.8	548.2
AMBIENT CONDITIONS										
AMBIENT AIR TEMP	CSTMPTD	DEGF	64.8	69.2	74.4	79.5	80.7	63.9	72.2	83.3
WET BULB TEMP	U1WETBULB	DEGF	59.7	61.2	62.5	64.1	64.7	56.9	60.3	63.0
ATMOSPHERIC PRESSUR	1INAPE0001	PSIA	12.6	12.6	12.6	12.6	12.6	12.5	12.5	12.5
BOILER										
BOILER EFF (HL Method)	1SGAPX3550	%	90.0	89.9	89.9	89.8	89.9	90.2	90.0	89.8
BOILER EFF (Input-Output	1SGAPX3561	%	90.3	90.3	91.5	89.8	90.1	86.0	84.3	83.4
BLOWDOWN FLOW	MANUAL	KPPH								
SH SPRAY FLOW	1COAXI022A	KPPH	75.4	56.9	150.5	55.5	71.7	174.7	156.6	163.0

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PMAX SH SPRAY FLOW	1SGAPX3033	KPPH	126.8	82.8	211.7	64.5	83.9	247.9	214.6	220.1
RH SPRAY FLOW	1COAXI108A	KPPH	0.0	0.0	0.0	0.0	0.0	34.1	43.6	44.8
PMAX RH SPRAY FLOW	1SGAPX3918	KPPH	7.7	7.8	0.8	2.5	3.8	95.6	124.7	151.1
TOTAL AIR FLOW	1COAXI078S	%	86.9	86.0	86.2	85.5	82.5	81.7	83.8	85.0
EXCESS AIR	1SGBPX3512	%	15.00	15.27	15.56	15.80	15.48	13.06	12.08	10.35
TOTAL FUEL FLOW	1COAXI001A	TPH	345.9	344.0	344.2	342.7	343.2	370.9	375.4	377.9
PMAX BACKCALC COAL F	1SGAPX3504	TPH	341.1	341.0	341.2	340.0	339.7	339.7	339.2	339.2
REHEAT DAMPER POS	1COAXI136A	%	58.1	66.7	61.4	81.3	98.8	45.3	35.3	30.4
SUPERHEAT DAMPER PO	1COAXI135A	%	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this
BOILER DUTY (HEAT INPU	CALC	MBTU/HR								
BOILER CONDITIONS	Pulv O/S	manual								
EAST FLUE GAS O2	1COAXI079A	%	2.9	2.7	2.1	2.8	2.5	2.3	2.0	2.2
WEST FLUE GAS O2	1COAXI080A	%	3.4	3.2	3.4	3.2	2.5	3.0	3.0	2.7
SCRUB INLET SO2	1SAAKK0002	PPM	365.8	371.6	372.5	373.1	390.4	369.6	363.5	355.4
STACK NOX	1SAAKK0006	PPM	301.2	254.2	217.6	240.2	225.5	251.7	226.3	212.6
STACK NOX CONVERTED	1SAAKK0007		0.531	0.439	0.378	0.419	0.382	0.420	0.380	0.359
O2 TRIM SETPOINT	1COAXI220A	%	61.0	61.0	61.0	60.9	55.4	41.0	42.9	44.2
CEM STACK VOL FLOW	1SAAKK0016	MSCFH	137.5	135.4	135.5	135.6	132.2	131.7	133.2	135.6
PMAX CALC STACK VOL F	1SGAPX3903	MSCFH	137.2	135.1	133.8	134.5	131.6	143.3	143.6	144.2
PMAX BLR GAS FLOW	1SGAPX3520	LB/HR	8,057,922	7,937,361	7,850,240	7,885,688	7,710,073	8,403,360	8,436,751	8,452,967
PMAX BLR AIR FLOW RAT	1SGAPX3522	LB/HR	7,433,423	7,315,324	7,229,910	7,267,214	7,090,824	7,734,807	7,758,108	7,772,853
BOILER HEAT DUTY										
BLR HEAT DUTY	1SGAPX3563	MBTU/HR	7639.6	7604.5	7718.9	7548.0	7585.1	7792.1	7749.9	7733.3
WATER WALLS HEAT DUT	1SGAPX3690	MBTU/HR	3244.0	3277.1	3190.3	3305.0	3298.6	3168.8	3158.0	3129.3
SSH PLATENS HEAT DUTY	1SGAPX3691	MBTU/HR	620.2	604.9	629.2	598.1	627.4	628.4	589.1	581.3
SSH INT SECTION HEAT D	1SGAPX3692	MBTU/HR	691.7	695.4	726.0	715.4	770.6	712.0	672.1	633.7
SSH OUTLET SECTION HE	1SGAPX3693	MBTU/HR	541.3	527.1	527.9	526.3	540.4	574.1	545.2	519.6
RH OUTLET SECTION HEA	1SGAPX3694	MBTU/HR	787.5	779.8	786.3	777.1	760.2	849.2	884.6	877.3
PSH SECTION HEAT DUTY	1SGAPX3695	MBTU/HR	886.8	884.1	931.0	817.0	780.1	912.7	1003.3	1062.4
ECON SECTION HEAT DU	1SGAPX3696	MBTU/HR	274.0	270.4	274.3	257.7	242.6	274.0	295.7	303.7
PRI RH SECTION HEAT DU	1SGAPX3697	MBTU/HR	412.5	410.4	394.3	418.5	397.0	440.1	424.9	461.2
TEMPS AIR/GAS										
AIR TEMP ENT SAH 1A	1COAXI124A	DEGF	74.8	78.4	81.9	85.8	87.4	73.2	81.1	90.3
AIR TEMP ENT SAH 1B	1COAXI125A	DEGF	75.6	79.1	82.8	86.8	88.8	74.7	81.1	90.2
AIR TEMP LVG SAH 1A	1COAXI149A	DEGF	685.6	688.3	690.5	687.9	686.8	682.5	692.2	706.3
AIR TEMP LVG SAH 1B	1COAXI150A	DEGF	679.4	684.4	689.6	682.7	681.0	679.5	694.8	713.0
FLAME GAS TEMP	1SGAPX3571	DEGF	3699.3	3734.8	3775.1	3739.6	3790.4	3597.9	3588.2	3592.6
SSH PLATENS GAS OUT T	1SGAPX3582	DEGF	2252.5	2261.9	2315.5	2245.4	2260.6	2222.1	2238.4	2257.0
SSH INT GAS IN TEMP	1SGAPX3591	DEGF	2252.5	2261.9	2315.5	2245.0	2260.5	2222.1	2238.4	2258.0
SSH INT GAS OUT TEMP	1SGAPX3592	DEGF	1977.4	1981.3	2019.8	1954.3	1943.3	1951.5	1982.3	2017.8
SSH OUTLET BANK GAS O	1SGAPX3602	DEGF	1758.4	1765.4	1801.8	1737.2	1714.7	1729.5	1773.2	1818.4
RH OUTLET BANK GAS OU	1SGAPX3612	DEGF	1435.5	1441.6	1471.5	1409.9	1386.5	1393.6	1427.0	1475.3
PRI RH BANKS GAS IN TE	1SGAPX3641	DEGF	1431.2	1450.1	1466.1	1431.3	1410.6	1569.8	1737.8	1827.2
RH SECTION GAS OUT TE	1SGATE1631	DEGF	758.7	759.8	757.5	755.5	754.7	744.3	736.0	745.2
TARGET RH EXIT GAS TE	1SGAPX3679	DEGF	760.1	760.1	760.1	760.1	760.1	760.0	759.9	760.0

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PSH OUTLET GAS TEMP	1SGAPX3622	DEGF	917.4	920.5	927.9	914.6	900.5	908.2	930.5	950.4
PSH / ECON EXIT GAS TE	1SGATE1625	DEGF	750.1	753.8	760.3	751 1	742.5	756.8	777.6	793.5
TARGET ECON EXIT GAS	1SGAPX3688	DEGF	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0
AVE ECON EXIT GAS TEM	1SGAPX3015	DEGF	756.8	758.3	762.0	754.0	748.0	754.0	766.5	780.5
TARGET EXIT GAS TEMP	1INAPX3086	DEGF	760.0	760.1	760.0	760.0	760.0	760.1	760 1	760.0
TEMPS STM/WTR										
ECON INLET WATER TEM	1COAXI025A	DEGF	548.0	548.2	548.4	547.7	548.1	548.6	548.8	548.2
	1FWATE0990	DEGF	549.1	549.4	549.7	548.9	549.3	549.8	550.0	549.5
TSAT AT DRUM PRESSUR	1SGAPX3261	DEGF	680.8	681.1	680.7	680.3	680.6	680.3	680.3	680.4
1ST STAGE SH ATTEMP II	1SGATE0863	DEGF	725.9	728.9	742.1	723.4	719.4	734.9	746.3	755.7
	1SGATE0864	DEGF	732.1	726.7	726.5	720.6	719.4	731.6	737.1	741.6
1ST STAGE SH ATTEMP C	1COAXI098A	DEGF	724.8	724.6	733.9	720.4	716.4	731.3	740.3	746.3
	1COAXI099A	DEGF	724.2	723.7	724.1	718.9	718.1	723.6	731.7	740.2
2ND STAGE SH ATTEMP II	1SGATE0871	DEGF	789.9	791.4	822.5	784.9	779.9	808.0	819.8	828.3
	1SGATE0872	DEGF	802.9	794.2	790.8	784.6	790.3	800.7	802.9	815.9
2ND STAGE SH ATTEMP C	1COAXI093A	DEGF	779.4	785.6	798.5	780.5	772.4	783.1	797.0	802.4
	1COAXI094A	DEGF	791.5	785.8	768.8	776.8	779.9	772.9	778.3	788.8
SSH INT BANK OUTLET TE	1SGAPE0008	DEGF	896.7	897.5	901.4	891.5	898.0	890.9	897.1	901.0
MAIN STEAM TEMP	1COAXI015A	DEGF	1003.7	1001.0	1006.3	994.2	1004.9	1004.1	1004.7	1004.9
COLD REHEAT INLET TEM	1SGJTE0019	DEGF	633.3	630.8	635.3	625.5	632.9	624.8	622.5	622.8
	1SGJTE0022	DEGF	633.4	630.9	635.5	625.9	633.1	625.2	622.9	623.5
PRI RH SECTION STM OU	1SGATE1637	DEGF	751.3	748.4	748.2	745.5	746.7	731.9	717.1	725.1
RH TURBINE INLET TEMP	1COAXI104A	DEGF	1011.9	1005.4	1008.6	1001.3	997.4	1011.0	1007.5	1015.5
RH TURBINE INLET TEMP	1COAXI105A	DEGF	1005.9	999.3	1001.6	996.6	992.3	1003.3	998.6	1005.3
BLR HOT REHEAT AVE TE	1COAXI046A	DEGF								
STEAM TEMP PICKUP										
DRUM THRU PSH	1SGAPE0001	DEGF	48.3	46.9	53.7	41.2	38.6	52.7	61.0	68.1
PLATENS	1SGAPE0002	DEGF	71.9	68.7	77.6	65.2	67.8	76.9	75.1	78.8
SSH INT BANK	1SGAPE0003	DEGF	111.4	111.8	117.8	113.0	122.0	112.9	109.0	105.3
SSH OUT BANK	1SGAPE0004	DEGF	106.8	103.5	104.9	102.6	106.8	113.3	108.0	104.0
PRI RH SECTION	1SGAPE0005	DEGF	118.1	117.4	112.8	119.8	113.6	106.8	94.4	101.8
RH OUTLET SECTION	1SGAPE0006	DEGF	257.5	254.3	256.8	253.6	248.3	275.2	286.1	285.5
FLOWS WTR/STM										
FEEDWATER FLOW (FOX	1FWAFT0025	KPPH	6951.4	6983.7	6880.6	6985.8	6967.3	6831.9	6873.6	6815.1
FEEDWATER FLOW (CCS	1COAXI021A	KPPH	6720.4	6796.6	6631.5	6801.6	6780.1	6582.0	6623.2	6566.8
STEAM FLOW (FFW + SPI	1COAXI023A	KPPH	6794.3	6852.2	6779.2	6855.7	6849.9	6753.1	6776.6	6726.7
STEAM FLOW OFF 1ST ST	1COAXI024A	KPPH	6806.7	6846.2	6808.2	6828.2	6846.8	6781.4	6804.4	6757.1
PMAX THROTTLE FLOW	1FWAPX3352	KPPH	6845.6	6874.0	6830.2	6867.3	6853.0	6831.9	6833.0	6783.7
ECON OUTLET										
EAST ECON O2 PROBE 1/	1SGAAZ0030	%	4.0	3.7	3.1	2.9	2.5	2.8	1.9	2.9
EAST ECON O2 PROBE 2/	1SGAAZ0031	%	3.0	3.1	2.7	2.8	2.6	2.3	2.3	2.7
EAST ECON O2 PROBE 3/	1SGAAZ0032	%	2.3	2.3	1.8	2.3	2.1	1.9	1.8	1.9
EAST ECON O2 PROBE 4/	1SGAAZ0033	%	3.2	2.7	1.6	3.1	2.8	2.6	1.8	1.9
EAST FLUE GAS O2	1COAXI079A	%	2.9	2.7	2.1	2.8	2.5	2.3	2.0	2.2

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WEST ECON O2 PROBE 1	1SGAAZ0034	%	3.4	3.5	3.4	3.7	3.0	3.8	3.0	2.7
WEST ECON O2 PROBE 2	[redacted]	%	4.2	4.4	4.7	4.4	3.6	3.9	4.2	3.9
WEST ECON O2 PROBE 3	1SGAAZ0036	%	2.1	2.0	2.3	1.8	1.4	1.4	1.9	1.8
WEST ECON O2 PROBE 4	1SGAAZ0037	%	4.1	3.1	3.3	2.7	2.0	2.9	2.7	2.2
WEST FLUE GAS O2	1COAXI080A	%	3.4	3.2	3.4	3.2	2.5	3.0	3.0	2.7
SELECTED ECON OUT O2	1COAXI187A	%	3.14	2.96	2.74	2.96	2.51	2.65	2.49	2.42
TARGET ECON OUT O2	1COAXI188A	%	3.07	3.07	3.07	3.08	3.08	3.08	3.08	3.07
EXCESS AIR %	1SGBPX3512	%	15.0	15.3	15.6	15.8	15.5	13.1	12.1	10.3
CARBON DIOXIDE %	1SGBPX3513	%	21.7	21.9	22.1	21.9	22.5	22.3	22.5	22.6
AIR/DRAFT PRESSURE										
SEC AIR DUCT PR E	1SGBPT0256	INWC	5.0	4.9	4.0	4.6	4.2	4.9	4.3	4.0
SEC AIR DUCT PR W	1SGBPT0257	INWC	5.0	5.0	4.3	4.8	4.5	4.9	4.7	4.4
FURNACE PRESSURE	1COAXI083A	INWC	-0.5	-0.5	-0.6	-0.5	-0.6	-0.5	-0.4	-0.5
SG EAST FLUE GAS PR	1SGAPT0171	INWC	-0.1	-0.1	-0.3	-0.3	-0.3	-0.2	-0.1	-0.1
SG SEC SUPHTR GAS PR	1SGAPT0169	INWC	-0.9	-0.9	-0.9	-0.9	-1.0	-0.9	-0.8	-0.8
SG HORIZ RH OUT PR	1SGAPT0167	INWC	-3.1	-3.0	-3.0	-3.1	-3.1	-2.8	-2.6	-2.6
SG PENDANT OUT PR	1SGAPT0168	INWC	-1.5	-1.5	-1.5	-1.5	-1.6	-1.5	-1.5	-1.5
SG PRI SUPHTR OUT PR	1SGAPT0166	INWC	-2.6	-2.6	-2.7	-2.6	-2.6	-2.6	-2.7	-2.7
SG ECON OUTLET PR	1SGAPT0165	INWC	-3.1	-3.0	-3.1	-3.0	-2.9	-3.1	-3.2	-3.3
SEC AH 1A INLET PR	1SGAPT0164	INWC	-4.5	-4.5	-4.6	-4.3	-4.2	-4.4	-4.7	-4.7
SEC AH 1B INLET PR	1SGAPT0183	INWC	-4.5	-4.5	-4.6	-4.4	-4.2	-4.4	-4.6	-4.7
ID FAN SUCTION PRESS	1COAXI084A	INWC	-22.9	-22.4	-22.7	-22.7	-21.9	-21.2	-22.3	-23.1
ID FAN 1A OUTLET PR	1CCEPT0115	INWC	5.3	5.3	5.3	5.4	5.1	5.0	5.1	5.4
ID FAN 1B OUTLET PR	1CCEPT0116	INWC	5.0	5.0	5.1	5.1	5.0	4.7	4.9	5.2
ID FAN 1C OUTLET PR	1CCEPT0117	INWC	5.0	4.9	5.0	5.0	4.9	4.7	4.8	5.0
ID FAN 1D OUTLET PR	1CCEPT0118	INWC	5.1	5.1	5.2	5.2	5.0	4.8	5.0	5.2
BAGHOUSE CASING DELTA P										
A CASING	1CCBA40001	INWC	6.5	6.3	6.4	6.7	6.4	6.0	6.4	6.8
B CASING	1CCBB40001	INWC	6.7	6.4	6.5	6.8	6.6	6.3	6.6	6.9
C CASING	1CCBC40001	INWC	6.9	6.7	6.8	7.0	6.8	6.5	6.8	7.1
FORCED DRAFT FAN 1A										
FD Fan Disc Press- A	manual	INWC								
Sec Air Duct- East	manual	INWC								
SEC AIR FLOW 1A	1COAXI076R	%	78.4	77.8	77.9	77.2	74.3	73.6	75.7	76.5
FD FAN 1A FLOW	1SGBFT0097	KCFM	889.8	877.0	874.5	879.9	843.0	827.5	847.3	862.9
FAN BLADE PITCH	1COAXI153A	%	67.5	64.3	63.1	64.5	61.4	60.6	61.9	63.2
FD FAN 1A D/P	1SGBPT0218	INWC	13.5	11.9	11.2	11.5	11.0	11.4	11.2	11.1
MOTOR AMPS	1SGBKK0005	AMPS	236.0	224.0	217.2	222.7	213.9	213.4	211.9	215.7
CORR ACTUAL HEAD	1SGBKV0111	INWC	12.1	10.6	10.1	10.4	10.0	10.0	9.9	9.6
AIR HORSEPOWER	CALC	HP								
FORCED DRAFT FAN 1B										
FD Fan Disc Press- B	manual	INWC								

BOILER- OVERFIRE AIR/ BURNER TESTI **TEST SERIES for STATE of UTAH, September 6- 9, 2003**

NOTE: Master data download file and calculation spreadsheet. Insert ALL data and calcs here (in this spreadsheet) and then reference (copy) cells to other spreadsheets, graphs, etc. Reason-

PARAMETER	PT ID	UNITS	Test # 1 (Day1-T1) 9/6/03 Sat 8:15 9:30	Test # 2 (Day1-T2) 9/6/03 Sat 10:15 11:30	Test # 3 (Day1-T3) 9/6/03 Sat 12:30 13:30	Test # 4 (Day1-T4) 9/6/03 Sat 14:15 15:30	Test # 5 (Day1-T5) 9/6/03 Sat 15:45 16:45	Test # 6 (Day2-T1) 9/7/03 Sun 7:45 9:00	Test # 7 (Day2-T2) 9/7/03 Sun 9:45 10:45	Test # 8 (Day2-T3) 9/7/03 Sun 13:05 14:05
Sec Air Duct- West	manual	INWC								
SEC AIR FLOW 1B	1COAXI077R	%	80.3	79.4	79.7	79.0	76.1	75.3	77.1	78 3
FD FAN 1B FLOW	1SGBFT0098	KCFM	905.6	892.9	895.4	893.9	863.7	846.4	868.5	880.9
FAN BLADE PITCH	1COAXI154A	%	66.8	63.8	62.6	64.0	61.0	59.8	60.7	62.4
FD FAN 1B D/P	1SGBPT0219	INWC	13.6	12.4	11.4	11.9	11.0	11.5	11.3	11.3
MOTOR AMPS	1SGBKK0006	AMPS	244.7	232.7	228.0	230.6	223.6	224.0	222.6	224.7
CORR ACTUAL HEAD	1SGBKV0112	INWC	12.1	10.7	10.2	10.4	10.0	10.4	9.9	9.8
AIR HORSEPOWER	CALC	HP								
PRI AIR DUCT PRESS	1COAXI072A	INWC	44.3	44.5	44.8	44.6	44.5	44.0	44.5	44.2
PRIMARY AIR FAN 2A										
PA FAN FLOW 2A	1COAXI074R	%	30.9	30.7	31.0	30.9	30.7	31.1	31.5	31.8
MOTOR AMPS	1SGBKK0007	AMPS	307.3	307.2	305.4	304.5	303.7	308.7	307.7	306.8
INLET VANE CONTROL %	1COAXI239A	%	30.9	31.0	31.6	31.6	31.7	31.5	32.0	32.9
PRIMARY AIR FAN 2B										
PA FAN FLOW 2B	1COAXI075R	%	32.1	32.0	32.1	32.0	32.0	32.6	32.6	32.9
MOTOR AMPS	1SGBKK0008	AMPS	316.4	315.6	313.9	312.7	311.9	317.9	316.7	315.2
INLET VANE CONTROL %	1COAXI240A	%	30.8	30.8	31.2	31.6	31.6	31.3	32.0	33.0
SECONDARY AIR HEATER 1A										
AIR ENT SEC AH 1A	1COAXI124A	DEGF	74.8	78.4	81.9	85.8	87.4	73.2	81.1	90.3
AIR LVG SEC AH 1A	1COAXI149A	DEGF	685.6	688.3	690.5	687.9	686.8	682.5	692.2	706.3
GAS ENT SEC AH 1A	1SGATE1650	DEGF	755.0	756.9	762.3	751.7	745.6	753.5	767.1	781.8
GAS LVG SEC AH 1A	1COAXI122A	DEGF	301.3	304.7	310.9	311.6	314.4	298.5	309.5	323.6
FLUE GAS TEMP DROP	CALC	DEGF	453.7	452.3	451.4	440.0	431.3	455.1	457.6	458.2
AIR HEATER TEMP HEAD	CALC	DEGF	680.2	678.5	680.4	665.9	658.3	680.4	685.9	691.5
DROP/HEAD	CALC	%	66.70	66.65	66.35	66.08	65.52	66.89	66.71	66.26
SAH 1A EFFICIENCY - AIR	1SGBPX3525	%	88.7	89.0	89.1	89.4	89.9	88.9	89.4	89.9
SAH 1A EFFICIENCY - GA	1SGBPX3526	%	59.3	59.1	59.4	59.2	58.4	61.7	60.9	59.4
SAH 1A AIR TO GAS LEAK	1SGBPX3527	%	23.6	23.8	22.1	21.9	21.6	16.4	18.5	21.8
SAH 1A LEAKAGE (O2 ME	1SGBPX3927	%	23.4	23.7	22.1	21.7	21.5	16.4	18.5	21.7
COLD END AVE TEMP	1SGBKV0008	DEGF	184.7	188.3	192.7	195.8	198.4	183.0	192.3	203.7
DIFFERENTIAL PRESS	1SGBPT0216	INWC	9.1	8.9	8.9	9.0	8.7	8.1	8.5	8.8
MOTOR AMPS	1SGBKK0001	AMPS	31.2	31.3	31.3	31.4	31.4	31.5	31.2	31.3
SECONDARY AIR HEATER 1B										
AIR ENT SEC AH 1B	1COAXI125A	DEGF	75.6	79.1	82.8	86.8	88.8	74.7	81.1	90.2
AIR LVG SEC AH 1B	1COAXI150A	DEGF	679.4	684.4	689.6	682.7	681.0	679.5	694.8	713.0
GAS ENT SEC AH 1B	1SGATE1651	DEGF	759.1	759.7	761.8	756.5	750.6	754.9	766.6	779.6
GAS LVG SEC AH 1B	1COAXI123A	DEGF	294.2	298.2	300.8	303.4	305.6	292.7	300.6	310.5
FLUE GAS TEMP DROP	CALC	DEGF	464.9	461.5	461.0	453.1	444.9	462.2	466.0	469.2
AIR HEATER TEMP HEAD	CALC	DEGF	683.5	680.6	679.0	669.8	661.7	680.2	685.6	689.4
DROP/HEAD	CALC	%	68.01	67.81	67.89	67.66	67.24	67.95	67.97	68.05
SAH 1B EFFICIENCY - AIR	1SGBPX3530	%	89.6	89.8	89.7	90.0	90.5	89.6	89.6	89.7
SAH 1B EFFICIENCY - GA	1SGBPX3531	%	62.8	63.1	62.3	62.7	63.0	64.6	63.6	63.2
SAH 1B AIR TO GAS LEAK	1SGBPX3532	%	17.0	15.2	18.6	16.2	13.5	11.0	14.8	16.1

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BOILER- OVERFIRE AIR/ BURNER TESTI TEST SERIES for STATE of UTAH, September 6- 9, 2003

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PARAMETER	PT ID	UNITS	Test # 1 (Day1-T1) 9/6/03 Sat 8:15 9:30	Test # 2 (Day1-T2) 9/6/03 Sat 10:15 11:30	Test # 3 (Day1-T3) 9/6/03 Sat 12:30 13:30	Test # 4 (Day1-T4) 9/6/03 Sat 14:15 15:30	Test # 5 (Day1-T5) 9/6/03 Sat 15:45 16:45	Test # 6 (Day2-T1) 9/7/03 Sun 7:45 9:00	Test # 7 (Day2-T2) 9/7/03 Sun 9:45 10:45	Test # 8 (Day2-T3) 9/7/03 Sun 13:05 14:05
SAH 1B LEAKAGE (O2 ME	1SGBPX3930	%	16.9	15.1	18.3	16.0	13.4	10.9	14.7	16.0
COLD END AVE TEMP	1SGBKV0009	DEGF	192.0	196.4	199.9	204.6	207.1	190.2	198.1	210.0
DIFFERENTIAL PRESS	1SGBPT0217	INWC	9.1	9.0	9.0	9.0	8.6	8.1	8.5	8.9
MOTOR AMPS	1SGBKK0002	AMPS	31.4	31.3	31.5	31.1	31.3	31.4	31.3	31.3
PRIMARY AIR HEATER 2A										
AIR ENT PRI AH 2A	1SGBTE0911	DEGF	115.2	119.7	123.0	126.6	128.4	115.5	122.0	130.3
AIR LVG PRI AH 2A	1SGBTE0917	DEGF	525.1	523.3	523.2	520.1	516.9	515.5	516.2	516.8
GAS ENT PRI AH 2A	1SGATE1650	DEGF	755.0	756.9	762.3	751.7	745.6	753.5	767.1	781.8
GAS LVG PRI AH 2A	1COAXI120A	DEGF	301.2	300.1	301.3	300.0	298.9	300.5	300.9	300.8
FLUE GAS TEMP DROP	CALC	DEGF	453.8	456.8	461.0	451.6	446.7	453.1	466.2	481.0
AIR HEATER TEMP HEAD	CALC	DEGF	639.9	637.3	639.3	625.1	617.2	638.0	645.1	651.5
DROP/HEAD	CALC	%	70.92	71.69	72.12	72.25	72.38	71.01	72.27	73.83
PAH 2A EFFICIENCY - AIR	1SGBPX3535	%	64.1	63.4	62.7	63.0	62.9	62.7	61.1	59.3
PAH 2A EFFICIENCY - GA	1SGBPX3536	%	70.9	71.6	72.1	72.3	72.4	71.0	72.3	73.9
COLD END AVE TEMP	1SGBKV0006	DEGF	204.7	206.7	208.9	210.3	210.8	205.9	209.0	213.6
DIFFERENTIAL PRESS	1SGBPT0214	INWC	2.1	2.0	2.0	1.9	1.9	2.7	2.7	2.5
MOTOR AMPS	1SGBKK0003	AMPS	3.5	3.6	3.5	3.5	3.4	3.3	3.3	3.3
PRIMARY AIR HEATER 2B										
AIR ENT PRI AH 2B	1SGBTE0912	DEGF	113.7	118.1	121.9	125.3	127.6	112.9	120.2	128.1
AIR LVG PRI AH 2B	1SGBTE0918	DEGF	510.7	511.2	510.6	507.3	504.3	504.5	505.4	505.9
GAS ENT PRI AH 2B	1SGATE0710	DEGF	760.7	759.9	758.3	754.7	749.7	758.8	771.5	780.0
GAS LVG PRI AH 2B	1COAXI121A	DEGF	302.2	301.2	302.0	300.3	299.0	301.4	301.8	301.8
FLUE GAS TEMP DROP	CALC	DEGF	458.5	458.7	456.3	454.4	450.7	457.4	469.7	478.2
AIR HEATER TEMP HEAD	CALC	DEGF	647.0	641.7	636.4	629.4	622.1	645.9	651.3	651.9
DROP/HEAD	CALC	%	70.87	71.47	71.70	72.19	72.44	70.82	72.12	73.36
PAH 2B EFFICIENCY - AIR	1SGBPX3540	%	61.5	61.3	60.7	60.5	60.4	61.1	59.7	58.0
PAH 2B EFFICIENCY - GA	1SGBPX3541	%	70.8	71.4	71.8	72.3	72.5	70.5	71.9	73.3
COLD END AVE TEMP	1SGBKV0007	DEGF	209.8	211.3	213.6	213.9	214.4	209.0	212.6	216.3
DIFFERENTIAL PRESS	1SGBPT0215	INWC	1.9	1.8	1.7	1.6	1.6	2.3	2.3	2.2
MOTOR AMPS	1SGBKK0004	AMPS	3.4	3.4	3.4	3.3	3.3	3.4	3.4	3.4
TOTAL AH LKG (CO2 MET	1SGBPX3933	%	9.6	9.1	11.4	11.4	11.1	7.7	9.8	12.4
TOTAL AH LKG (GAS WT	1SGBPX3936	%	20.3	19.4	20.4	19.0	17.4	13.7	16.7	19.0
TOTAL AH LKG (O2 METH	1SGBPX3940	%	20.1	19.2	20.2	18.9	17.3	13.6	16.6	18.8
INDUCED DRAFT FAN 1A										
XFMR 1A1 AMPS	1CCEKK0001	AMPS	335.5	332.9	333.7	334.4	325.5	319.6	328.9	335.4
XFMR 1A2 AMPS	1CCEKK0002	AMPS	333.2	330.5	331.3	332.1	323.5	316.9	326.9	333.1
ID FAN 1A SPEED	1COAXI086A	RPM	814.2	806.6	814.0	816.0	800.7	781.2	803.6	826.1
INDUCED DRAFT FAN 1B										
XFMR 1B1 AMPS	1CCEKK0003	AMPS	353.3	348.5	350.3	350.4	341.5	336.5	345.1	351.8
XFMR 1B2 AMPS	1CCEKK0004	AMPS	356.1	351.3	353.4	352.9	343.4	339.0	347.8	354.7
ID FAN 1B SPEED	1COAXI087A	RPM	817.3	809.7	817.1	819.0	803.5	784.1	806.5	828.9
INDUCED DRAFT FAN 1C										

IP10_003413

BOILER- OVERFIRE AIR/ BURNER TESTII TEST SERIES for STATE of UTAH, September 6- 9, 2003

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PARAMETER	PT ID	UNITS	Test # 1 (Day1-T1) 9/6/03 Sat 8:15 9:30	Test # 2 (Day1-T2) 9/6/03 Sat 10:15 11:30	Test # 3 (Day1-T3) 9/6/03 Sat 12:30 13:30	Test # 4 (Day1-T4) 9/6/03 Sat 14:15 15:30	Test # 5 (Day1-T5) 9/6/03 Sat 15:45 16:45	Test # 6 (Day2-T1) 9/7/03 Sun 7:45 9:00	Test # 7 (Day2-T2) 9/7/03 Sun 9:45 10:45	Test # 8 (Day2-T3) 9/7/03 Sun 13.05 14:05
XFMR 1C1 AMPS	1CCEKK0005	AMPS	365.2	361.3	363.5	363.8	356.3	355.1	359.1	365.5
XFMR 1C2 AMPS	1CCEKK0006	AMPS	359.5	356.2	358.2	357.8	350.4	349.0	353.7	359.8
ID FAN 1C SPEED	1COAXI088A	RPM	832.1	824.5	831.9	833.9	818.3	798.6	821.3	844.2
INDUCED DRAFT FAN 1D										
XFMR 1D1 AMPS	1CCEKK0007	AMPS	357.4	352.6	355.2	355.8	347.5	343.1	349.7	357.6
XFMR 1D2 AMPS	1CCEKK0008	AMPS	358.9	354.3	356.7	357.7	349.4	344.4	351.8	360.1
ID FAN 1D SPEED	1COAXI089A	RPM	823.6	815.8	823.5	825.4	809.9	790.1	812.8	835.5
TOTAL ID FAN AMPS	CALC	AMPS	2818.9	2787.5	2802.2	2804.9	2737.6	2703.7	2763.0	2818.0
COAL PULVERIZER 1A										
PULV COAL FLOW	1COAXI002A	TPH	43.5	45.7	44.3	43.3	43.2	48.3	49.0	51.3
FEEDER SPEED	1SGAPEFDRA	%	64.0	67.2	65.1	63.6	63.6	71.1	72.0	75.5
PULV PA FLOW	1COAXI056A	%	86.2	83.5	85.9	85.9	85.5	85.3	84.4	86.5
PA DAMPER POS	1COAKS021A	%	67.0	69.5	68.0	67.4	67.4	71.5	71.4	75.4
PULV INLET TEMP	1SGATE0639	DEGF	254.5	263.8	261.1	256.2	255.7	318.0	322.8	334.2
PULV DISCH TEMP	1COAXI064A	DEGF	149.7	149.9	149.9	149.9	149.9	149.9	150.0	149.9
PULV DIFF PRESS	1SGAPT0150	INWC	10.2	11.2	11.1	10.6	10.7	11.4	11.5	14.4
PULV AMPS	1SGAKK0001	AMPS	71.6	73.7	73.2	72.6	72.7	71.0	70.3	68.2
AMPS/DP	CALC		7.01	6.60	6.57	6.82	6.80	6.25	6.10	4.73
TPH/AMPS	CALC		0.61	0.62	0.60	0.60	0.59	0.68	0.70	0.75
TPH/DP	CALC		4.26	4.09	3.97	4.06	4.04	4.26	4.25	3.56
COAL PULVERIZER 1B										
PULV COAL FLOW	1COAXI003A	TPH	51.1	50.5	50.7	50.8	50.7	54.6	55.3	56.3
FEEDER SPEED	1SGAPEFDRB	%	75.2	74.3	74.6	74.8	74.6	80.3	81.3	82.8
PULV PA FLOW	1COAXI057A	%	88.6	88.5	88.6	88.6	88.6	90.9	91.3	92.1
PA DAMPER POS	1COAKS022A	%	81.2	80.7	81.0	81.3	81.1	83.8	84.2	85.3
PULV INLET TEMP	1SGATE0640	DEGF	289.9	286.9	291.8	288.6	286.6	341.6	345.0	353.2
PULV DISCH TEMP	1COAXI065A	DEGF	151.2	151.2	151.4	151.0	150.7	151.3	151.3	151.3
PULV DIFF PRESS	1SGAPT0151	INWC	15.6	15.4	15.3	15.6	15.6	16.3	16.6	16.7
PULV AMPS	1SGAKK0002	AMPS	58.3	58.4	58.3	58.7	59.0	57.6	57.7	57.6
AMPS/DP	CALC		3.75	3.80	3.80	3.77	3.79	3.54	3.48	3.44
TPH/AMPS	CALC		0.88	0.86	0.87	0.87	0.86	0.95	0.96	0.98
TPH/DP	CALC		3.29	3.29	3.31	3.26	3.26	3.35	3.34	3.36
COAL PULVERIZER 1C										
PULV COAL FLOW	1COAXI004A	TPH	49.9	49.3	49.5	49.6	49.5	53.3	54.0	55.0
FEEDER SPEED	1SGAPEFDRC	%	73.4	72.6	72.8	73.0	72.8	78.4	79.4	80.8
PULV PA FLOW	1COAXI058A	%	87.8	87.5	87.7	87.8	87.7	90.1	90.3	91.0
PA DAMPER POS	1COAKS023A	%	71.4	71.2	71.7	71.8	71.1	76.0	77.9	80.3
PULV INLET TEMP	1SGATE0641	DEGF	277.5	274.9	278.2	278.0	278.3	330.7	337.9	345.9
PULV DISCH TEMP	1COAXI066A	DEGF	151.4	151.1	151.2	151.2	151.0	151.1	151.2	151.2
PULV DIFF PRESS	1SGAPT0152	INWC	12.7	12.6	12.7	13.0	12.8	15.6	16.6	17.7
PULV AMPS	1SGAKK0003	AMPS	67.8	68.9	70.0	70.1	70.6	65.4	64.6	63.7
AMPS/DP	CALC		5.35	5.47	5.50	5.41	5.52	4.19	3.89	3.60
TPH/AMPS	CALC		0.74	0.72	0.71	0.71	0.70	0.81	0.84	0.86

IP10_003414

BOILER- OVERFIRE AIR/ BURNER TESTI TEST SERIES for STATE of UTAH, September 6- 9, 2003

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PARAMETER	PT ID	UNITS	Test # 1 (Day1-T1) 9/6/03 Sat 8:15 9:30	Test # 2 (Day1-T2) 9/6/03 Sat 10:15 11:30	Test # 3 (Day1-T3) 9/6/03 Sat 12:30 13:30	Test # 4 (Day1-T4) 9/6/03 Sat 14:15 15:30	Test # 5 (Day1-T5) 9/6/03 Sat 15:45 16:45	Test # 6 (Day2-T1) 9/7/03 Sun 7:45 9:00	Test # 7 (Day2-T2) 9/7/03 Sun 9:45 10:45	Test # 8 (Day2-T3) 9/7/03 Sun 13:05 14:05
TPH/DP	CALC		3.94	3.92	3.89	3.83	3.87	3.41	3.25	3.10
COAL PULVERIZER 1D										
PULV COAL FLOW	1COAXI005A	TPH	50.4	49.8	50.0	50.1	50.0	53.9	54.5	55.5
FEEDER SPEED	1SGAPEFDRD	%	74.1	73.3	73.6	73.7	73.6	79.3	80.2	81.7
PULV PA FLOW	1COAXI059A	%	88.4	88.0	88.1	88.2	88.1	90.6	91.0	91.6
PA DAMPER POS	1COAKS024A	%	70.1	69.9	70.1	70.3	70.2	73.1	74.5	75.5
PULV INLET TEMP	1SGATE0642	DEGF	283.2	282.1	285.9	284.0	281.9	327.3	325.1	329.5
PULV DISCH TEMP	1COAXI067A	DEGF	152.6	152.1	152.2	152.3	152.2	152.7	153.0	153.0
PULV DIFF PRESS	1SGAPT0153	INWC	15.2	15.0	15.1	15.4	15.4	17.2	17.5	17.6
PULV AMPS	1SGAKK0004	AMPS	59.8	60.3	60.4	61.0	61.4	60.5	60.6	60.9
AMPS/DP	CALC		3.94	4.02	4.01	3.97	3.99	3.53	3.46	3.46
TPH/AMPS	CALC		0.84	0.83	0.83	0.82	0.81	0.89	0.90	0.91
TPH/DP	CALC		3.32	3.32	3.32	3.26	3.25	3.14	3.11	3.16
COAL PULVERIZER 1E										
PULV COAL FLOW	1COAXI006A	TPH	49.5	49.0	49.1	49.2	49.1	53.0	53.6	52.5
FEEDER SPEED	1SGAPEFDRE	%	72.9	72.0	72.3	72.4	72.3	77.9	78.8	77.2
PULV PA FLOW	1COAXI060A	%	88.1	87.6	87.8	87.6	87.9	90.1	90.5	89.8
PA DAMPER POS	1COAKS025A	%	82.2	81.7	81.8	82.8	82.8	88.9	89.9	86.8
PULV INLET TEMP	1SGATE0643	DEGF	274.2	274.1	277.4	275.5	274.7	328.4	333.6	336.6
PULV DISCH TEMP	1COAXI068A	DEGF	151.0	151.0	150.9	150.8	150.8	150.9	151.1	151.1
PULV DIFF PRESS	1SGAPT0154	INWC	18.9	18.9	19.0	19.3	19.4	21.3	21.5	20.2
PULV AMPS	1SGAKK0005	AMPS	66.0	66.2	66.4	66.8	66.9	68.3	68.2	66.7
AMPS/DP	CALC		3.49	3.50	3.49	3.47	3.45	3.21	3.18	3.30
TPH/AMPS	CALC		0.75	0.74	0.74	0.74	0.73	0.78	0.79	0.79
TPH/DP	CALC		2.62	2.59	2.58	2.56	2.53	2.49	2.50	2.60
COAL PULVERIZER 1F										
PULV COAL FLOW	1COAXI007A	TPH	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this
FEEDER SPEED	1SGAPEFDRF	%	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this
PULV PA FLOW	1COAXI061A	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PA DAMPER POS	1COAKS026A	%	1.2	1.2	1.2	1.3	1.3	1.2	1.2	1.2
PULV INLET TEMP	1SGATE0644	DEGF	90.4	93.9	97.1	100.2	101.6	88.2	95.2	102.6
PULV DISCH TEMP	1COAXI069A	DEGF	90.2	89.7	90.7	91.7	92.4	91.0	90.8	92.6
PULV DIFF PRESS	1SGAPT0155	INWC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PULV AMPS	1SGAKK0006	AMPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMPS/DP	CALC		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	0.00	0.00	0.00
TPH/AMPS	CALC		#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
TPH/DP	CALC		#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
COAL PULVERIZER 1G										
PULV COAL FLOW	1COAXI008A	TPH	49.5	48.9	49.1	49.2	49.1	52.9	53.5	54.5
FEEDER SPEED	1SGAPEFDRG	%	72.7	71.9	72.2	72.3	72.2	77.8	78.8	80.2
PULV PA FLOW	1COAXI062A	%	89.0	88.7	88.4	88.7	88.8	91.2	91.2	92.1
PA DAMPER POS	1COAKS027A	%	73.7	72.2	72.6	73.3	73.0	76.1	76.5	77.1
PULV INLET TEMP	1SGATE0645	DEGF	283.4	277.6	279.5	276.5	276.0	334.2	340.2	338.3
PULV DISCH TEMP	1COAXI070A	DEGF	151.1	150.8	151.2	151.2	151.1	151.1	151.0	151.0

BOILER- OVERFIRE AIR/ BURNER TESTI TEST SERIES for STATE of UTAH, September 6- 9, 2003

NOTE: Master data download file and calculation spreadsheet. Insert ALL data and calcs here (in this spreadsheet) and then reference (copy) cells to other spreadsheets, graphs, etc. Reason-

PARAMETER	PT ID	UNITS	Test # 1 (Day1-T1) 9/6/03 Sat 8:15 9:30	Test # 2 (Day1-T2) 9/6/03 Sat 10:15 11:30	Test # 3 (Day1-T3) 9/6/03 Sat 12:30 13:30	Test # 4 (Day1-T4) 9/6/03 Sat 14:15 15:30	Test # 5 (Day1-T5) 9/6/03 Sat 15:45 16:45	Test # 6 (Day2-T1) 9/7/03 Sun 7:45 9:00	Test # 7 (Day2-T2) 9/7/03 Sun 9:45 10:45	Test # 8 (Day2-T3) 9/7/03 Sun 13:05 14:05
PULV DIFF PRESS	1SGAPT0156	INWC	12.4	10.0	10.3	10.6	10.6	13.0	13.2	13.6
PULV AMPS	1SGAKK0007	AMPS	53.3	60.7	61.5	61.5	61.5	53.4	52.8	53.0
AMPS/DP	CALC		4.28	6.06	5.97	5.80	5.79	4.10	4.00	3.90
TPH/AMPS	CALC		0.93	0.80	0.80	0.80	0.80	0.99	1.01	1.03
TPH/DP	CALC		3.98	4.88	4.77	4.63	4.62	4.07	4.06	4.02
COAL PULVERIZER 1H										
PULV COAL FLOW	1COAXI009A	TPH	51.3	50.7	50.9	51.0	50.9	54.8	55.5	52.2
FEEDER SPEED	1SGAPEFDRH	%	75.5	74.6	74.9	75.0	74.9	80.6	81.6	76.8
PULV PA FLOW	1COAXI063A	%	88.8	88.3	88.8	88.7	88.6	91.0	91.3	90.5
PA DAMPER POS	1COAKS028A	%	78.7	78.8	78.9	79.8	79.7	85.7	86.8	84.7
PULV INLET TEMP	1SGATE0646	DEGF	292.8	293.1	294.5	293.5	291.3	337.7	351.1	340.2
PULV DISCH TEMP	1COAXI071A	DEGF	150.1	150.2	150.5	150.3	149.9	149.4	149.8	150.1
PULV DIFF PRESS	1SGAPT0157	INWC	17.5	17.3	17.4	17.7	18.0	21.0	20.6	17.5
PULV AMPS	1SGAKK0008	AMPS	60.3	60.4	60.4	60.7	61.2	63.0	62.1	59.0
AMPS/DP	CALC		3.44	3.48	3.47	3.44	3.41	3.00	3.02	3.38
TPH/AMPS	CALC		0.85	0.84	0.84	0.84	0.83	0.87	0.89	0.89
TPH/DP	CALC		2.92	2.92	2.93	2.89	2.83	2.61	2.70	2.99
PULV AMP SWING										
A PULV	1SGAPE1001	AMPS	11.04	10.26	10.02	9.13	9.42	10.08	8.91	8.03
B PULV	1SGAPE1002	AMPS	6.04	6.14	6.42	6.05	6.43	6.26	6.28	5.89
C PULV	1SGAPE1003	AMPS	16.62	16.42	16.21	16.26	14.92	13.85	12.67	9.43
D PULV	1SGAPE1004	AMPS	6.11	6.67	6.31	6.29	6.71	6.17	6.28	5.88
E PULV	1SGAPE1005	AMPS	7.12	6.73	6.22	6.62	6.74	7.15	7.34	6.93
F PULV	1SGAPE1006	AMPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
G PULV	1SGAPE1007	AMPS	7.25	10.77	9.56	10.32	9.55	5.65	5.69	5.60
H PULV	1SGAPE1008	AMPS	5.91	5.92	5.58	6.01	5.76	6.15	5.90	5.75
CLEANLINESS FACTOR										
WATERWALLS	1SGAPX3577		0.82	0.81	0.75	0.82	0.79	0.83	0.82	0.80
PSH SECTION	1SGAPX3628		0.92	0.92	0.92	0.90	0.92	0.95	0.94	0.92
SSH PLATEN SECTION	1SGAPX3587		0.75	0.67	0.65	0.65	0.63	0.90	0.81	0.78
SSH INTERMEDIATE SEC	1SGAPX3598		0.70	0.70	0.70	0.74	0.80	0.73	0.68	0.62
SSH OUTLET SECTION	1SGAPX3608		0.76	0.73	0.70	0.76	0.81	0.83	0.75	0.67
PRIMARY RH SECTION	1SGAPX3648		0.66	0.66	0.73	0.65	0.64	0.74	0.79	0.77
RH OUTLET SECTION	1SGAPX3618		0.96	0.99	1.00	1.08	1.25	0.96	0.92	0.85
ECONOMIZER SECTION	1SGAPX3638		0.91	0.89	0.87	0.86	0.85	0.85	0.80	0.75

IP10_003416

BOILER- OVERFIRE A

NOTE: Master data do all calcs referenced back to the master file, if changes needed, make it once and everything automatically updates

PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
[redacted]									
UNIT LOAD	949.7	949.9	947.3	949.6	950.3	950.1	952.0	950.3	950.3
TURBINE THROTTLE PRE	2409.1	2413.5	2399.2	2397.5	2394.3	2399.5	2395.4	2404.9	2397.0
THROTTLE TEMP	1005.6	1004.7	1004.7	1004.7	1004.5	1000.7	1006.8	1003.7	1004.9
TURBINE STEAM FLOW	6772.4	6803.4	6778.9	6823.2	6830.8	6815.5	6801.9	6780.3	6704.6
STEAM FLOW (FW + SSF)	6742.1	6786.8	6748.0	6800.3	6812.1	6810.4	6762.1	6766.0	6667.4
FDW FLOW TO ECONOMI	6522.5	6684.5	6610.7	6727.4	6733.7	6742.7	6633.5	6700.2	6564.1
TOTAL COAL FLOW	376.5	370.2	366.4	368.5	378.4	379.1	380.5	381.5	377.2
TOTAL FUEL FLOW	376.3	370.8	366.5	368.5	378.8	379.4	381.7	383.5	378.0
TOTAL AIR FLOW	82.1	80.8	78.8	79.6	77.0	77.6	89.8	87.1	92.2
EAST FLUE GAS O2	1.9	1.7	1.5	1.9	1.7	1.3	2.7	2.8	3.4
WEST FLUE GAS O2	2.0	2.1	2.4	2.3	1.6	2.1	4.0	3.5	4.2
EAST FLUE GAS COMB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OVERFIRE AIR									
OFA SW 1/3 DMPR P	0.9	0.9	53.3	1.3	1.5	40.6	55.0	0.9	0.9
OFA SE 1/3 DMPR P	2.3	2.1	58.0	2.0	2.0	54.5	60.4	1.9	1.9
OFA NW 1/3 DMPR P	0.0	0.0	56.6	0.0	0.0	39.3	41.2	0.6	0.4
OFA NE 1/3 DMPR P	6.0	6.0	99.0	5.8	5.8	63.9	98.7	5.7	5.8
OFA SW 2/3 DMPR P	59.2	39.9	0.0	0.0	0.0	0.0	0.0	0.0	50.2
OFA SE 2/3 DMPR P	55.6	44.3	0.2	0.2	0.1	0.0	0.0	0.0	50.8
OFA NW 2/3 DMPR P	58.0	34.7	0.0	0.0	0.0	0.0	0.0	0.7	45.8
OFA NE 2/3 DMPR P	98.5	44.0	0.1	0.1	0.0	0.0	0.0	0.0	98.8
OFA SW INLET DMPR P	99.0	98.9	99.1	0.2	0.6	99.6	99.5	99.2	99.2
OFA SE INLET DMPR P	98.8	98.7	99.1	0.0	0.0	98.5	98.6	99.1	99.1
OFA NW INLET DMPR P	97.7	97.6	97.7	0.7	0.4	97.8	97.8	97.9	97.9
OFA NE INLET DMPR P	98.6	98.6	98.7	0.0	0.0	98.2	98.3	98.7	98.7
OFA TO TOTAL AIR RATIO	12.6	8.7	9.0	4.5	4.7	8.1	8.4	4.7	11.3
SW OFA FLOW	239.5	172.3	171.9	126.6	122.1	152.3	180.6	107.5	246.5
SE OFA FLOW	229.3	161.6	161.4	103.4	95.1	138.1	167.7	80.6	241.7
NW OFA FLOW	244.3	166.0	171.7	54.1	51.4	152.8	184.0	94.0	240.5
NE OFA FLOW	233.2	156.6	163.6	70.5	67.7	144.5	173.1	101.5	236.0
TOTAL OFA AIR	949.2	652.0	666.7	352.5	337.2	586.1	707.6	382.7	964.4
[redacted]									
West Side O2	2.53	2.64	2.91	2.62	1.97	2.50	4.36	3.96	4.03
East Side O2	2.72	2.37	2.39	2.62	2.09	1.58	4.05	4.37	5.26
O2 Average	2.63	2.51	2.65	2.62	2.03	2.04	4.20	4.16	4.64
West Side CO2	16.11	16.01	15.55	15.73	16.19	15.72	14.20	13.92	13.62
East Side CO2	15.73	16.03	16.35	16.28	16.72	17.02	14.63	14.90	13.83

IP10_003417

BOILER- OVERFIRE A

NOTE: Master data do all calcs referenced back to the master file, if changes needed, make it once and everything automatically updates

PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
CO2 Average	15.92	16.02	15.95	16.00	16.46	16.37	14.42	14.41	13.73
West Side NOx	238.25	264.80	165.24	252.90	274.17	243.69	291.43	243.16	216.66
East Side NOx	272.87	169.91	274.04	234.77	266.83	263.52	288.74	289.27	260.46
NOx Average	255.56	217.36	219.64	243.83	270.50	253.61	290.09	266.21	238.56
Low Range CO Analyzer We	640.6	217.4	202.0	330.2	878.9	342.2	1.3	23.2	90.8
Low Range CO Analyzer Ea	263.8	361.1	453.5	287.6	384.4	1151.1	1.3	20.9	20.7
Low Range CO Analyzer Ave	452.2	289.3	327.8	308.9	631.7	746.7	1.3	22.1	55.7
High Range CO Analyzer W	629.7	227.5	209.9	341.6	855.5	351.8	1.0	20.7	90.4
High Range CO Analyzer Ea	289.4	381.8	468.7	303.9	398.5	1412.8	1.4	17.9	19.5
High Range CO Analyzer Av	459.5	304.6	339.3	322.7	627.0	882.3	1.2	19.3	54.9
Stack CO	347.6	243.3	278.7	276.3	806.6	1040.2	2.9	14.3	37.1
Stack CO- corrected	302.4	211.5	241.5	239.6	696.3	898.7	2.5	12.5	32.6
CO converted #/mbtu	0.237	0.165	0.189	0.189	0.536	0.695	0.002	0.010	0.028
CO converted #/hr	2892	2003	2227	2239	6332	8227	26	126	342
[redacted]									
CO2	13.00	13.05	13.33	13.28	13.68	13.60	12.25	12.46	12.01
NOx PPM	190	207	203	233	223	193	228	239	210
NOx lb/mbtu	0.314	0.342	0.327	0.377	0.350	0.306	0.399	0.413	0.375
Stack Flow	131,848,964	130,581,936	127,134,930	128,834,958	125,399,856	126,227,274	141,645,808	138,486,883	144,615,446
CALCS									
Excess Air @ furn	-2.8	1.9	2.1	6.0	5.3	1.7	7.2	12.6	6.0
Diff O2 CR- O2 grid	-0.68	-0.60	-0.71	-0.52	-0.38	-0.31	-0.86	-0.97	-0.87
NOX Reduction (#/mbtu), s	20.1	10.2	15.3	base	base	14.4	3.5	base	10.1
NOX Reduction (#/mbtu), v	68.5	54.7	61.8	40.3	51.1	72.9	32.6	28.1	41.1
CO Increase (ppm), same C	20.8	-13.3	0.8	base	base	22.5	-398.8	base	61.7
	20.8	-13.3	0.8	base	base	22.5	[redacted]	base	61.7
CO Increase (ppm), max ba	-9.4	-132.7	-78.6	-91.7	-31.3	-75.1	-34946.0	153.4	28.2
CO Increase (#/mbtu)	20.1	-14.4	0.0	base	base	22.8	-394.6	base	62.9
[redacted]									
HHV	11527	11639	11556	11629	11752	11743	11722	11368	11212
MAF HHV	14118	14215	14195	14199	14260	14210	14198	14055	13984
% MOISTURE	9.47	9.21	9.48	9.19	8.99	8.87	8.88	9.61	9.97
% ASH	8.88	8.91	9.11	8.91	8.6	8.49	8.56	9.51	9.85
% SULFUR	0.5	0.54	0.51	0.5	0.51	0.5	0.49	0.49	0.5
% CARBON	64.97	65.4	65.1	65.38	65.8	66.01	65.98	64.22	63.6
% HYDROGEN	4.16	4.16	4.11	4.3	4.29	4.29	4.26	4.09	4.02
% NITROGEN	1.38	1.4	1.37	1.39	1.36	1.4	1.4	1.33	1.31

IP10_003418

BOILER- OVERFIRE A

NOTE: Master data doall calcs referenced back to the master file, if changes needed, make it once and everything automatically updates

PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
% OXYGEN	10.64	10.38	10.32	10.33	10.45	10.44	10.43	10.75	10.75
COAL..AS-FIRED									
HHVC	12663.0	11995.0	12591.2	12591.2	12591.2	12591.2	12591.2	12591.2	12591.2
% TOTAL MOISTURE	4.5	6.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3
% ASH	8.7	10.1	8.8	8.8	8.8	8.8	8.8	8.8	8.8
% SULFUR	0.7	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9
% CARBON	70.4	66.9	70.5	70.5	70.5	70.5	70.5	70.5	70.5
% HYDROGEN	4.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
% NITROGEN	1.6	1.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6
% OXYGEN	9.4	10.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
FLY ASH ANALYSIS									
LOI AVE (IPSC)	1.28		1.27	1.36	1.32			0.62	0.66
LOI EAST (IPSC)	1.45		1.35	1.47	1.35			0.59	0.66
LOI WEST (IPSC)	1.11		1.18	1.24	1.28			0.65	0.66
AEA EAST	41		30	33	40			16	16
AEA WEST	23		28	28	25			14	16
COLOR EAST	511		511	511	511			611	611
COLOR WEST	611		511	511	511			611	611
[illegible]									
UNIT									
GROSS CAPACITY	949.7	949.9	947.3	949.6	950.3	950.1	952.0	950.3	950.3
AUXILIARY POWER	54.3	53.4	51.5	53.2	52.4	53.0	58.3	57.7	58.8
GROSS UNIT HEAT RATE									
NET UNIT HEAT RATE I/O									
% AUX POWER									
STEAM TURBINE									
CORR GROSS CAPACITY									
NET TURBINE HEAT RATE									
CYCLE LOSSES									
THROTTLE FLOW									
FEEDWATER FLOW	6522.5	6684.5	6610.7	6727.4	6733.7	6742.7	6633.5	6700.2	6564.1
CORR THROTTLE FLOW									
ECONOMIZER INLET TEM	548.4	548.0	547.9	548.1	548.2	547.8	548.5	547.4	547.5
AMBIENT CONDITIONS									
AMBIENT AIR TEMP	86.2	85.9	69.5	73.1	76.5	78.5	80.3	60.0	62.4
WET BULB TEMP	63.6	63.8	56.0	59.2	58.6	60.4	61.2	48.2	52.6
ATMOSPHERIC PRESSUR	12.5	12.5	12.4	12.4	12.4	12.4	12.4	12.5	12.5
BOILER									
BOILER EFF (HL Method)	89.9	89.9	90.2	90.0	90.0	89.9	89.5	89.9	89.6
BOILER EFF (Input-Output	84.0	84.3	86.0	84.9	82.9	82.9	83.2	80.7	83.0
BLOWDOWN FLOW									
SH SPRAY FLOW	224.0	104.5	140.1	74.5	80.0	69.3	131.2	67.2	105.6

BOILER- OVERFIRE A

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	Test # 9 (Day2-T4)	Test # 10 (Day2-T5)	Test # 11 (Day3-T1)	Test # 12 (Day3-T2)	Test # 13 (Day3-T3)	Test # 14 (Day3-T4)	Test # 15 (Day3-T5)	Test # 16 (Day4-T1)	Test # 17 (Day4-T2)
	9/7/03 Sun	9/7/03 Sun	9/8/03 Mon	9/8/03 Mon	9/8/03 Mon	9/8/03 Mon	9/8/03 Mon	9/9/03 Tue	9/9/03 Tue
	15:15	17:00	8:15	10:30	12:30	14:30	16:15	7:30	9:45
PARAMETER	16:15	18:00	9:30	11:30	13:45	15:30	17:15	8:45	11:00
PMAX SH SPRAY FLOW	272.3	162.4	218.3	138.6	155.9	161.5	227.0	105.8	171.1
RH SPRAY FLOW	0.0	0.0	0.0	0.0	0.0	0.0	41.0	0.0	75.7
PMAX RH SPRAY FLOW	1.5	3.0	16.7	18.6	20.5	22.2	145.6	2.7	257.0
TOTAL AIR FLOW	82.1	80.8	78.8	79.6	77.0	77.6	89.8	87.1	92.2
EXCESS AIR	9.80	10.63	11.05	10.52	9.99	9.78	15.62	17.30	17.27
TOTAL FUEL FLOW	376.3	370.8	366.5	368.5	378.8	379.4	381.7	383.5	378.0
PMAX BACKCALC COAL F	340.6	341.5	339.4	341.0	342.4	343.4	342.7	338.4	335.8
REHEAT DAMPER POS	35.8	64.3	46.0	60.6	47.8	42.6	37.8	49.6	30.4
SUPERHEAT DAMPER PO	No good data for this	No good data for this	No good data for this	72.9	98.4	101.1	100.8	104.9	104.9
BOILER DUTY (HEAT INPU									
BOILER CONDITIONS									
EAST FLUE GAS O2	1.9	1.7	1.5	1.9	1.7	1.3	2.7	2.8	3.4
WEST FLUE GAS O2	2.0	2.1	2.4	2.3	1.6	2.1	4.0	3.5	4.2
SCRUB INLET SO2	364.8	371.2	389.8	376.4	388.5	385.2	341.1	339.2	310.0
STACK NOX	190.6	207.1	201.9	231.8	222.1	193.4	228.7	239.2	208.4
STACK NOX CONVERTED	0.318	0.343	0.328	0.379	0.352	0.307	0.403	0.415	0.374
O2 TRIM SETPOINT	39.1	39.1	36.1	37.5	24.5	26.1	47.5	44.1	51.5
CEM STACK VOL FLOW	132.5	131.1	127.2	129.2	125.5	126.5	141.8	138.9	144.4
PMAX CALC STACK VOL F	140.2	138.7	137.0	139.6	140.1	140.8	153.7	152.6	154.9
PMAX BLR GAS FLOW	8,219,923	8,085,586	8,000,840	8,119,549	8,162,400	8,203,191	8,869,406	8,866,303	8,953,434
PMAX BLR AIR FLOW RAT	7,543,303	7,416,964	7,337,680	7,457,787	7,480,976	7,520,028	8,239,992	8,215,296	8,367,700
BOILER HEAT DUTY									
BLR HEAT DUTY	7763.6	7677.6	7713.3	7659.5	7698.7	7714.9	7788.8	7565.1	7665.7
WATER WALLS HEAT DU	3125.7	3237.0	3186.8	3261.4	3245.9	3246.5	3176.1	3229.0	3145.6
SSH PLATENS HEAT DUT	632.7	672.6	621.3	685.4	649.9	619.9	594.3	601.0	528.6
SSH INT SECTION HEAT D	708.0	721.6	680.2	676.6	638.4	650.3	702.3	638.5	611.7
SSH OUTLET SECTION HE	522.7	513.7	549.4	510.0	514.0	494.1	499.4	502.7	508.6
RH OUTLET SECTION HEA	839.4	792.8	843.1	776.1	833.4	858.2	831.6	796.4	861.1
PSH SECTION HEAT DUTY	975.1	869.7	952.2	886.8	978.6	1012.7	1040.9	969.1	1083.4
ECON SECTION HEAT DU	280.6	252.1	274.4	257.3	272.9	283.1	301.7	277.1	300.8
PRI RH SECTION HEAT DU	354.8	399.4	332.8	401.4	356.2	343.2	484.6	378.6	577.1
TEMPS AIR/GAS									
AIR TEMP ENT SAH 1A	93.8	94.0	79.1	82.3	86.1	88.5	90.6	69.7	72.5
AIR TEMP ENT SAH 1B	94.4	95.3	80.8	83.1	85.9	88.8	90.8	71.4	73.1
AIR TEMP LVG SAH 1A	705.5	699.1	683.6	689.8	698.8	702.2	706.6	707.9	716.2
AIR TEMP LVG SAH 1B	708.3	702.7	686.3	691.2	704.5	715.5	716.7	709.2	714.9
FLAME GAS TEMP	3661.3	3698.3	3716.9	3683.5	3692.9	3691.7	3492.7	3463.2	3432.3
SSH PLATENS GAS OUT T	2277.3	2238.6	2281.6	2213.1	2249.9	2268.2	2196.2	2139.3	2178.7
SSH INT GAS IN TEMP	2277.3	2238.6	2281.6	2213.1	2249.9	2268.2	2196.2	2139.3	2178.7
SSH INT GAS OUT TEMP	2002.1	1953.0	2009.0	1945.9	1999.1	2015.0	1943.0	1906.7	1959.8
SSH OUTLET BANK GAS (	1795.3	1746.5	1785.9	1741.6	1794.8	1820.0	1759.1	1722.9	1774.9
RH OUTLET BANK GAS O	1457.7	1421.7	1436.9	1425.0	1458.0	1474.3	1449.6	1424.5	1459.1
PRI RH BANKS GAS IN TE	1470.1	1429.8	1437.4	1416.6	1453.4	1465.0	1727.1	1429.8	2017.6
RH SECTION GAS OUT TE	753.6	764.5	737.6	756.5	745.7	741.3	750.3	760.8	755.1
TARGET RH EXIT GAS TE	760.0	760.0	760.1	760.0	760.0	760.0	760.0	760.0	760.0

BOILER- OVERFIRE A

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PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
PSH OUTLET GAS TEMP	938.5	918.4	916.1	911.8	930.4	942.4	949.8	938.3	957.5
PSH / ECON EXIT GAS TE	782.6	766.1	759.5	756.3	776.6	786.7	798.6	793.2	812.2
TARGET ECON EXIT GAS	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0
AVE ECON EXIT GAS TEM	775.4	766.9	754.0	761.4	770.2	775.5	786.1	786.9	795.9
TARGET EXIT GAS TEMP	760.0	760.0	759.9	760.0	760.0	760.0	760.1	760.0	760.0
TEMPS STM/WTR									
ECON INLET WATER TEM	548.4	548.0	547.9	548.1	548.2	547.8	548.5	547.4	547.5
	549.7	549.3	549.1	549.4	549.5	549.0	549.7	548.6	548.7
TSAT AT DRUM PRESSUR	680.9	681.5	680.2	680.8	680.4	680.4	680.3	680.4	680.1
1ST STAGE SH ATTEMP I	746.2	733.7	744.6	732.2	741.5	752.9	755.3	736.8	750.2
	735.1	722.1	728.8	725.5	733.3	728.0	736.1	737.2	752.6
1ST STAGE SH ATTEMP C	738.4	727.4	736.5	726.1	734.2	743.8	746.1	733.2	743.2
	733.9	720.3	723.6	721.8	727.3	718.5	727.1	732.2	746.7
2ND STAGE SH ATTEMP I	827.4	812.1	823.8	807.0	812.7	828.3	830.7	804.1	811.1
	813.0	794.1	790.6	803.3	809.0	784.2	794.9	810.4	821.7
2ND STAGE SH ATTEMP C	792.6	804.2	801.7	792.7	798.8	817.5	808.3	793.9	794.8
	778.1	768.1	769.6	792.4	796.8	776.4	775.2	800.1	802.4
SSH INT BANK OUTLET TE	901.0	902.8	895.8	903.6	902.9	903.9	907.5	903.2	902.2
MAIN STEAM TEMP	1005.6	1004.7	1004.7	1004.7	1004.5	1000.7	1006.8	1003.7	1004.9
COLD REHEAT INLET TEM	635.0	633.8	633.3	633.7	633.9	630.6	624.2	632.3	614.4
	635.3	634.1	633.6	633.9	634.1	630.8	624.7	632.5	615.2
PRI RH SECTION STM OU	735.7	748.4	726.9	749.3	734.5	726.0	732.0	741.3	728.4
RH TURBINE INLET TEMP	1015.9	1011.5	1006.8	1006.6	1010.5	1009.2	1005.0	1007.5	1014.9
RH TURBINE INLET TEMP	1007.6	1004.4	998.4	997.9	999.4	997.9	994.8	998.0	1003.4
BLR HOT REHEAT AVE TE									
STEAM TEMP PICKUP									
DRUM THRU PSH	60.0	47.0	56.4	48.3	57.1	60.0	65.5	56.1	71.4
PLATENS	84.0	79.3	77.2	81.1	80.1	75.2	76.1	74.5	71.4
SSH INT BANK	115.8	116.9	110.1	111.0	105.2	107.0	115.8	106.5	103.5
SSH OUT BANK	104.5	101.6	108.9	101.0	101.3	96.8	99.5	100.3	102.8
PRI RH SECTION	100.8	114.7	93.4	115.5	100.3	95.4	107.6	108.9	113.5
RH OUTLET SECTION	275.8	259.4	275.7	253.0	270.6	277.4	268.0	261.5	280.8
FLOWS WTR/STM									
FEEDWATER FLOW (FOX	6769.1	6933.3	6859.7	6950.0	6968.9	6965.4	6882.8	6933.9	6817.9
FEEDWATER FLOW (CCS	6522.5	6684.5	6610.7	6727.4	6733.7	6742.7	6633.5	6700.2	6564.1
STEAM FLOW (FFW + SPF	6742.1	6786.8	6748.0	6800.3	6812.1	6810.4	6762.1	6766.0	6667.4
STEAM FLOW OFF 1ST ST	6772.5	6802.6	6779.2	6826.2	6831.3	6817.2	6802.5	6780.1	6704.8
PMAX THROTTLE FLOW	6802.8	6844.2	6827.3	6863.4	6885.8	6896.4	6866.3	6800.4	6735.5
ECON OUTLET									
EAST ECON O2 PROBE 1/	2.7	2.9	2.0	3.1	2.5	1.4	4.5	4.0	5.0
EAST ECON O2 PROBE 2/	2.5	2.3	2.0	2.2	2.1	1.7	3.4	3.1	3.9
EAST ECON O2 PROBE 3/	1.7	1.5	1.3	1.7	1.5	1.2	2.2	2.4	2.8
EAST ECON O2 PROBE 4/	1.5	1.4	1.1	1.8	1.4	1.0	2.4	3.0	3.4
EAST FLUE GAS O2	1.9	1.7	1.5	1.9	1.7	1.3	2.7	2.8	3.4

BOILER- OVERFIRE A

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PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
WEST ECON O2 PROBE 1	2.1	2.7	2.6	2.6	2.1	2.4	4.2	3.6	3.5
WEST ECON O2 PROBE 2	3.1	3.2	3.4	3.0	2.3	3.3	5.5	4.9	6.3
WEST ECON O2 PROBE 3	1.5	1.3	1.5	1.4	0.8	1.3	2.4	2.0	2.6
WEST ECON O2 PROBE 4	1.2	1.2	2.0	2.1	1.3	1.6	4.0	3.5	4.4
WEST FLUE GAS O2	2.0	2.1	2.4	2.3	1.6	2.1	4.0	3.5	4.2
SELECTED ECON OUT O2	1.95	1.91	1.94	2.10	1.65	1.73	3.34	3.19	3.77
TARGET ECON OUT O2	3.07	3.07	3.08	3.08	3.08	3.08	3.08	3.09	3.09
EXCESS AIR %	9.8	10.6	11.0	10.5	10.0	9.8	15.6	17.3	17.3
CARBON DIOXIDE %	23.1	23.2	23.1	22.9	23.4	23.4	21.6	21.7	21.1
AIR/DRAFT PRESSURE									
SEC AIR DUCT PR E	3.6	3.9	3.7	4.7	4.2	3.6	4.7	4.9	4.6
SEC AIR DUCT PR W	4.0	4.3	4.0	4.8	4.5	3.9	4.9	4.8	4.8
FURNACE PRESSURE	-0.5	-0.6	-0.4	-0.5	-0.5	-0.4	-0.5	-0.6	-0.5
SG EAST FLUE GAS PR	-0.3	-0.2	-0.1	-0.3	-0.3	-0.3	-0.2	-0.3	-0.2
SG SEC SUPHTR GAS PR	-0.8	-0.9	-0.8	-0.9	-0.9	-0.8	-0.9	-0.9	-0.8
SG HORIZ RH OUT PR	-2.6	-2.9	-2.5	-2.9	-2.5	-2.4	-2.8	-2.9	-2.8
SG PENDANT OUT PR	-1.5	-1.5	-1.4	-1.4	-1.4	-1.3	-1.6	-1.6	-1.6
SG PRI SUPHTR OUT PR	-2.7	-2.5	-2.5	-2.4	-2.5	-2.5	-3.0	-2.9	-3.0
SG ECON OUTLET PR	-3.1	-2.9	-2.9	-2.8	-2.9	-2.9	-3.6	-3.4	-3.6
SEC AH 1A INLET PR	-4.5	-4.2	-4.3	-4.2	-4.2	-4.3	-5.1	-5.0	-5.3
SEC AH 1B INLET PR	-4.5	-4.2	-4.3	-4.3	-4.2	-4.3	-5.1	-4.9	-5.2
ID FAN SUCTION PRESS	-22.0	-21.7	-20.6	-20.9	-20.4	-20.8	-25.0	-23.6	-25.5
ID FAN 1A OUTLET PR	5.2	5.1	5.0	5.1	4.9	5.0	6.1	5.7	6.2
ID FAN 1B OUTLET PR	5.0	4.9	4.8	4.9	4.6	4.8	5.9	5.4	5.9
ID FAN 1C OUTLET PR	4.9	4.8	4.7	4.8	4.5	4.7	5.7	5.3	5.8
ID FAN 1D OUTLET PR	5.1	5.0	4.9	4.9	4.7	4.9	5.9	5.5	6.0
BAGHOUSE CASING DELT									
A CASING	6.4	6.5	6.0	6.0	6.0	6.3	7.2	6.7	7.2
B CASING	6.6	6.6	6.0	6.1	6.3	6.3	7.2	6.8	7.3
C CASING	6.6	6.9	6.3	6.3	6.4	6.5	7.6	7.2	7.6
FORCED DRAFT FAN 1A									
FD Fan Disc Press- A									
Sec Air Duct- East									
SEC AIR FLOW 1A	73.9	72.5	70.8	71.5	69.0	69.6	81.3	78.8	83.8
FD FAN 1A FLOW	833.5	825.7	791.3	805.5	774.4	774.3	917.8	871.7	925.4
FAN BLADE PITCH	60.4	60.2	57.0	59.6	57.0	56.2	68.2	64.4	67.1
FD FAN 1A D/P	10.4	10.4	9.7	10.9	9.8	9.5	12.4	12.5	12.6
MOTOR AMPS	207.7	208.0	201.9	207.4	201.2	200.6	232.3	225.5	232.5
CORR ACTUAL HEAD	9.4	9.5	8.8	9.6	9.0	8.7	10.9	11.0	11.3
AIR HORSEPOWER									
FORCED DRAFT FAN 1B									
FD Fan Disc Press- B									

BOILER- OVERFIRE A

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PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
Sec Air Duct- West									
SEC AIR FLOW 1B	75.6	74.3	72.4	73.3	70.8	71.3	82.8	80.3	85.0
FD FAN 1B FLOW	850.3	841.5	811.9	827.1	793.6	796.0	929.9	888.6	936.0
FAN BLADE PITCH	59.9	59.6	56.4	58.8	56.0	55.9	67.6	63.7	66.7
FD FAN 1B D/P	10.4	10.5	9.9	10.9	10.0	9.6	12.6	12.7	12.8
MOTOR AMPS	218.9	220.0	211.9	217.7	209.9	210.9	241.0	235.8	242.0
CORR ACTUAL HEAD	9.3	9.6	8.8	9.7	8.9	8.8	11.3	11.4	11.3
AIR HORSEPOWER									
PRI AIR DUCT PRESS	44.4	44.2	44.3	44.3	44.3	44.6	44.3	44.6	44.5
PRIMARY AIR FAN 2A									
PA FAN FLOW 2A	31.4	31.3	31.5	31.5	31.5	31.6	31.8	32.1	32.3
MOTOR AMPS	306.6	305.9	308.6	308.0	308.3	308.7	305.6	313.0	310.1
INLET VANE CONTROL %	33.2	33.3	32.3	32.5	33.0	33.1	33.3	32.0	32.2
PRIMARY AIR FAN 2B									
PA FAN FLOW 2B	32.6	32.4	32.5	32.6	32.8	32.9	33.2	33.6	33.9
MOTOR AMPS	314.4	313.9	316.9	316.6	316.8	317.1	314.6	322.2	320.7
INLET VANE CONTROL %	33.1	33.1	32.3	32.3	32.8	33.0	33.2	31.9	32.1
SECONDARY AIR HEATER									
AIR ENT SEC AH 1A	93.8	94.0	79.1	82.3	86.1	88.5	90.6	69.7	72.5
AIR LVG SEC AH 1A	705.5	699.1	683.6	689.8	698.8	702.2	706.6	707.9	716.2
GAS ENT SEC AH 1A	776.7	769.6	756.7	763.9	773.1	781.9	791.2	787.9	793.6
GAS LVG SEC AH 1A	324.8	325.4	306.6	312.2	320.3	325.9	324.3	307.1	310.3
FLUE GAS TEMP DROP	451.9	444.1	450.1	451.7	452.8	456.0	466.9	480.9	483.3
AIR HEATER TEMP HEAD	683.0	675.6	677.6	681.6	687.0	693.4	700.6	718.3	721.1
DROP/HEAD	66.17	65.74	66.42	66.27	65.91	65.76	66.64	66.95	67.02
SAH 1A EFFICIENCY - AIR	89.9	89.9	89.7	89.2	89.9	90.3	89.2	88.6	88.8
SAH 1A EFFICIENCY - GA	59.8	60.7	61.2	61.2	62.3	63.0	59.4	60.3	57.0
SAH 1A AIR TO GAS LEAK	19.8	15.9	16.2	15.6	11.1	8.7	22.9	21.3	32.3
SAH 1A LEAKAGE (O2 ME	19.8	15.8	16.1	15.5	11.1	8.7	22.7	21.0	31.9
COLD END AVE TEMP	205.7	207.3	190.4	193.9	200.1	203.7	204.1	185.9	188.1
DIFFERENTIAL PRESS	8.4	8.3	7.7	8.1	7.5	7.7	9.6	9.0	9.7
MOTOR AMPS	31.1	31.2	31.1	31.2	30.8	30.8	30.9	30.9	30.9
SECONDARY AIR HEATER									
AIR ENT SEC AH 1B	94.4	95.3	80.8	83.1	85.9	88.8	90.8	71.4	73.1
AIR LVG SEC AH 1B	708.3	702.7	686.3	691.2	704.5	715.5	716.7	709.2	714.9
GAS ENT SEC AH 1B	774.8	764.6	751.9	759.8	767.6	769.4	781.6	785.9	798.4
GAS LVG SEC AH 1B	313.3	312.7	299.0	302.4	308.3	311.3	309.2	298.9	302.7
FLUE GAS TEMP DROP	461.5	451.9	453.0	457.4	459.4	458.1	472.4	487.0	495.7
AIR HEATER TEMP HEAD	680.4	669.3	671.2	676.7	681.7	680.5	690.8	714.5	725.3
DROP/HEAD	67.82	67.52	67.49	67.59	67.38	67.31	68.38	68.16	68.34
SAH 1B EFFICIENCY - AIR	90.1	90.4	90.1	89.9	90.2	90.3	89.4	89.3	89.1
SAH 1B EFFICIENCY - GA	63.2	62.8	63.6	63.9	64.3	63.5	64.0	63.5	64.4
SAH 1B AIR TO GAS LEAK	15.3	15.8	12.5	11.9	10.2	12.5	14.6	15.3	12.7

IP10_003423

BOILER- OVERFIRE A

NOTE: *Master data do all calcs referenced back to the master file, if changes needed, make it once and everything automatically updates*

PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
SAH 1B LEAKAGE (O2 ME	15.2	15.7	12.4	11.7	10.1	12.4	14.4	15.2	12.6
COLD END AVE TEMP	214.4	214.9	196.4	200.9	205 6	209.0	210.5	193.3	197.4
DIFFERENTIAL PRESS	8.4	8.3	7.8	8.1	7.7	7.8	9.6	9.1	9.8
MOTOR AMPS	31.3	31.3	31.0	31.1	30.8	30.9	31.0	31.1	31.5
PRIMARY AIR HEATER 2A									
AIR ENT PRI AH 2A	133.2	134.4	120.3	123.0	126.8	129.0	129.0	110.2	112.7
AIR LVG PRI AH 2A	513.8	512.5	513.4	517.2	513.3	514.2	514.7	526.9	527.6
GAS ENT PRI AH 2A	776.7	769.6	756.7	763.9	773.1	781.9	791.2	787.9	793.6
GAS LVG PRI AH 2A	300.8	300.5	300.9	299.3	299.6	300.7	297.9	301.0	301.3
FLUE GAS TEMP DROP	475.9	469.1	455.8	464.6	473.5	481.3	493.3	487.0	492.3
AIR HEATER TEMP HEAD	643.6	635.2	636.4	640.9	646.3	653.0	662.2	677.8	680.9
DROP/HEAD	73.95	73.85	71.62	72.49	73.26	73.71	74.49	71.85	72.30
PAH 2A EFFICIENCY - AIR	59.1	59.5	61.8	61.6	59.8	59.0	58.2	61.4	60.9
PAH 2A EFFICIENCY - GA	74.0	73.9	71.6	72.4	73.3	73.7	74.5	71.9	72.2
COLD END AVE TEMP	215.5	215.3	208.0	208.6	211.7	212.7	211.7	203.7	204.6
DIFFERENTIAL PRESS	2.4	2.4	2.4	2.3	2.4	2.6	2.6	3.0	2.8
MOTOR AMPS	3.3	3.4	3.3	3.3	3.3	3.3	3.3	3.3	3.3
PRIMARY AIR HEATER 2B									
AIR ENT PRI AH 2B	132.6	133.5	119.6	121.3	124.0	126.6	127.1	108.9	110.8
AIR LVG PRI AH 2B	501.8	499.8	501.3	505.4	500.9	500.7	500.8	513.0	518.6
GAS ENT PRI AH 2B	772.3	761.6	754.1	764.2	773.3	775.5	790.1	792.1	801.5
GAS LVG PRI AH 2B	301.9	301.2	301.7	300.3	300.6	301.1	299.1	301.4	301.8
FLUE GAS TEMP DROP	470.4	460.4	452.4	463.9	472.7	474.4	490.9	490.7	499.7
AIR HEATER TEMP HEAD	639.7	628.0	634.5	642.9	649.3	648.9	662.9	683.2	690.6
DROP/HEAD	73.53	73.30	71.30	72.16	72.81	73.11	74.06	71.82	72.36
PAH 2B EFFICIENCY - AIR	57.5	58.0	60.4	60.2	58.6	58.1	57.1	59.7	59.3
PAH 2B EFFICIENCY - GA	73.6	73.5	71.2	71.9	72.6	72.9	73.8	71.5	72.1
COLD END AVE TEMP	218.4	218.6	212.2	212.2	213.9	215.8	215.0	208.2	209.6
DIFFERENTIAL PRESS	2.1	2.0	2.2	2.2	2.2	2.2	2.3	2.3	2.2
MOTOR AMPS	3.4	3.4	3.5	3.4	3.4	3.3	3.3	3.5	3.5
TOTAL AH LKG (CO2 MET	13.6	14.1	10.4	9.1	8.7	9.4	10.8	8.7	10.2
TOTAL AH LKG (GAS WT	17.5	15.8	14.4	13.7	10.6	10.5	18.8	18.3	21.9
TOTAL AH LKG (O2 METH	17.4	15.8	14.3	13.6	10.6	10.5	18.6	18.1	21.6
INDUCED DRAFT FAN 1A									
XFMR 1A1 AMPS	328.0	321.7	313.7	317.7	309.8	313.9	353.2	340.0	358.4
XFMR 1A2 AMPS	326.0	319.5	311.8	315.6	307.8	312.4	350.4	337.4	355.1
ID FAN 1A SPEED	807.4	802.2	773.8	783.9	773.0	782.3	870.9	834.7	871.7
INDUCED DRAFT FAN 1B									
XFMR 1B1 AMPS	341.4	338.1	328.2	331.7	324.7	327.3	371.5	358.5	376.4
XFMR 1B2 AMPS	343.5	340.1	330.3	334.1	327.0	329.3	374.3	361.6	379.5
ID FAN 1B SPEED	810.1	804.7	776.6	786.8	775.8	785.1	874.0	837.9	875.0
INDUCED DRAFT FAN 1C									

IP10_003424

BOILER- OVERFIRE A

NOTE: Master data do all calcs referenced back to the master file, if changes needed, make it once and everything automatically updates

PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
XFMR 1C1 AMPS	356.3	353.3	349.9	349.3	346.7	349.6	385.8	369.2	387.4
XFMR 1C2 AMPS	351.4	348.3	344.4	343.1	341.0	343.7	380.8	363.9	382.6
ID FAN 1C SPEED	825.0	819.5	790.9	801.3	789.9	799.5	889.7	853.1	890.7
INDUCED DRAFT FAN 1D									
XFMR 1D1 AMPS	346.8	344.5	336.9	340.1	333.7	336.7	376.5	363.0	379.8
XFMR 1D2 AMPS	349.6	347.6	338.1	341.4	335.0	338.5	379.5	364.6	381.4
ID FAN 1D SPEED	816.6	811.3	782.6	793.0	781.8	791.2	880.8	844.2	881.6
TOTAL ID FAN AMPS	2743.0	2713.1	2653.2	2673.1	2625.6	2651.4	2972.0	2858.3	3000.6
COAL PULVERIZER 1A									
PULV COAL FLOW	51.0	50.1	49.6	49.9	51.3	51.4	51.6	51.7	50.3
FEEDER SPEED	75.0	73.8	73.0	73.4	75.5	75.6	75.9	76.1	74.0
PULV PA FLOW	87.2	88.3	87.0	86.5	85 8	86.6	87.1	89.4	91.6
PA DAMPER POS	74.9	73.5	72.2	72.2	75.2	75.4	75.6	77.7	75.4
PULV INLET TEMP	334.8	316.6	311.0	300.3	336.6	338.7	340.6	305.4	297.9
PULV DISCH TEMP	149.8	150.0	150.2	149.8	150.0	150.0	150.0	150.3	150.1
PULV DIFF PRESS	13.9	13.4	11.9	12.4	13.8	14.3	14.6	15.3	14.3
PULV AMPS	67.9	68.2	70.6	70.3	68.1	67.2	66.5	65.4	64.8
AMPS/DP	4.90	5.09	5.95	5.68	4.94	4.68	4.56	4.26	4.52
TPH/AMPS	0.75	0.74	0.70	0.71	0.75	0.77	0.78	0.79	0.78
TPH/DP	3.68	3.75	4.18	4.03	3.72	3.58	3.54	3.37	3.51
COAL PULVERIZER 1B									
PULV COAL FLOW	56.1	55.2	54.6	54.9	56.4	56.5	56.7	56.8	56.3
FEEDER SPEED	82.5	81.2	80.3	80.8	82.9	83.1	83.4	83.5	82.8
PULV PA FLOW	91.8	91.3	90.8	91.0	92.0	92.1	92.2	92.4	92.0
PA DAMPER POS	85.3	83.9	83.6	84.1	85.9	85.7	85.3	85.4	85.4
PULV INLET TEMP	344.5	330.3	318.3	311.7	347.2	351.5	357.9	324.2	322.1
PULV DISCH TEMP	151.3	151.2	151.5	151.2	151.2	151.5	151.5	151.2	151.2
PULV DIFF PRESS	16.7	16.4	16.3	16.7	17.3	16.8	16.6	17.2	16.9
PULV AMPS	58.1	58.4	58.2	59.0	58.3	57.4	57.1	58.5	58.4
AMPS/DP	3.48	3.56	3.57	3.53	3.38	3.41	3.44	3.40	3.45
TPH/AMPS	0.97	0.95	0.94	0.93	0.97	0.98	0.99	0.97	0.96
TPH/DP	3.36	3.37	3.35	3.29	3.27	3.35	3.41	3.30	3.32
COAL PULVERIZER 1C									
PULV COAL FLOW	54.7	53.8	53.3	53.6	55.0	55.1	55.3	55.5	55.0
FEEDER SPEED	80.5	79.2	78.4	78.8	80.9	81.1	81.4	81.6	80.9
PULV PA FLOW	91.1	90.7	90.1	90.1	91.3	91.4	91.3	91.4	91.4
PA DAMPER POS	80.3	79.7	77.1	78.8	80.5	81.1	81.1	79.6	80.1
PULV INLET TEMP	346.3	339.5	335.5	332.1	360.7	349.0	347.4	367.1	339.6
PULV DISCH TEMP	151.2	151.3	151.4	151.2	151.4	151.2	151.1	151.2	151.1
PULV DIFF PRESS	17.4	17.1	16.1	17.1	17.9	17.9	18.1	17.2	17.4
PULV AMPS	63.4	64.0	65.8	63.5	62.7	63.2	63.6	61.2	62.9
AMPS/DP	3.65	3.74	4.10	3.72	3.51	3.54	3.52	3.55	3.62
TPH/AMPS	0.86	0.84	0.81	0.84	0.88	0.87	0.87	0.91	0.87

BOILER- OVERFIRE A

NOTE: Master data do all calcs referenced back to the master file, if changes needed, make it once and everything automatically updates

PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
TPH/DP	3.15	3.15	3.32	3.13	3.07	3.08	3.06	3.22	3.17
COAL PULVERIZER 1D									
PULV COAL FLOW	55.3	54.5	53.9	54.2	55.6	55.7	55.9	56.0	55.6
FEEDER SPEED	81.4	80.1	79.3	79.7	81.8	82.0	82.3	82.4	81.7
PULV PA FLOW	91.5	90.9	90.6	90.7	91.7	91.7	91.8	91.9	91.6
PA DAMPER POS	75.1	74.4	74.4	73.7	75.5	75.1	74.6	73.6	74.9
PULV INLET TEMP	329.8	332.9	323.2	317.4	342.6	343.1	340.2	329.9	327.1
PULV DISCH TEMP	152.8	152.9	152.6	152.6	152.9	152.9	153.0	152.9	152.6
PULV DIFF PRESS	17.3	16.8	16.6	16.9	17.3	17.0	16.9	16.4	16.9
PULV AMPS	60.9	60.3	60.1	60.9	59.9	59.7	60.0	59.7	59.9
AMPS/DP	3.52	3.58	3.61	3.61	3.45	3.50	3.55	3.65	3.54
TPH/AMPS	0.91	0.90	0.90	0.89	0.93	0.93	0.93	0.94	0.93
TPH/DP	3.20	3.23	3.24	3.21	3.21	3.27	3.31	3.43	3.29
COAL PULVERIZER 1E									
PULV COAL FLOW	52.3	51.4	50.9	51.1	52.6	52.6	52.8	53.0	52.5
FEEDER SPEED	76.9	75.5	74.8	75.2	77.3	77.4	77.7	77.9	77.3
PULV PA FLOW	89.7	89.0	88.8	88.9	89.8	89.8	90.0	90.2	89.8
PA DAMPER POS	86.6	85.3	83.6	83.6	85.9	85.9	86.1	84.7	85.4
PULV INLET TEMP	338.9	330.4	338.9	335.3	343.1	340.3	347.8	354.2	329.2
PULV DISCH TEMP	151.2	151.1	151.0	151.1	150.8	151.1	150.9	151.0	151.0
PULV DIFF PRESS	19.9	19.4	18.7	18.9	19.3	19.4	19.5	18.6	19.0
PULV AMPS	66.3	65.7	64.6	64.7	65.0	65.5	65.7	64.3	64.0
AMPS/DP	3.33	3.38	3.46	3.43	3.37	3.37	3.38	3.45	3.36
TPH/AMPS	0.79	0.78	0.79	0.79	0.81	0.80	0.80	0.82	0.82
TPH/DP	2.63	2.65	2.72	2.71	2.72	2.71	2.72	2.84	2.76
COAL PULVERIZER 1F									
PULV COAL FLOW	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this
FEEDER SPEED	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this	No good data for this
PULV PA FLOW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PA DAMPER POS	1.2	1.2	1.3	1.3	1.3	1.3	1.2	1.2	1.2
PULV INLET TEMP	106.2	107.0	96.8	71.3	68.0	90.3	107.6	88.0	89.5
PULV DISCH TEMP	94.6	96.3	93.8	93.0	92.6	93.0	93.5	87.2	87.2
PULV DIFF PRESS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PULV AMPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMPS/DP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!
TPH/AMPS	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
TPH/DP	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
COAL PULVERIZER 1G									
PULV COAL FLOW	54.3	53.4	52.9	53.2	54.6	54.7	54.9	55.0	54.6
FEEDER SPEED	79.9	78.6	77.8	78.2	80.3	80.4	80.8	80.9	80.2
PULV PA FLOW	91.8	91.4	90.9	91.1	92.3	92.5	92.4	92.5	92.0
PA DAMPER POS	76.5	76.6	76.3	75.9	76.7	77.3	76.8	76.5	76.4
PULV INLET TEMP	337.7	332.2	355.5	347.9	343.3	357.5	355.9	360.8	341.4
PULV DISCH TEMP	151.2	151.0	151.1	151.1	151.1	151.1	150.9	151.2	151.0

IP10_003426

BOILER- OVERFIRE A

NOTE: Master data do all calcs referenced back to the master file, if changes needed, make it once and everything automatically updates

PARAMETER	Test # 9 (Day2-T4) 9/7/03 Sun 15:15 16:15	Test # 10 (Day2-T5) 9/7/03 Sun 17:00 18:00	Test # 11 (Day3-T1) 9/8/03 Mon 8:15 9:30	Test # 12 (Day3-T2) 9/8/03 Mon 10:30 11:30	Test # 13 (Day3-T3) 9/8/03 Mon 12:30 13:45	Test # 14 (Day3-T4) 9/8/03 Mon 14:30 15:30	Test # 15 (Day3-T5) 9/8/03 Mon 16:15 17:15	Test # 16 (Day4-T1) 9/9/03 Tue 7:30 8:45	Test # 17 (Day4-T2) 9/9/03 Tue 9:45 11:00
PULV DIFF PRESS	13.2	13.1	12.6	12.6	13.5	13.3	13.2	12.5	12.8
PULV AMPS	53.0	53.0	51.9	51.8	51.9	52.1	52.2	51.3	51.8
AMPS/DP	4.00	4.05	4.11	4.11	3.86	3.91	3.94	4.11	4.05
TPH/AMPS	1.03	1.01	1.02	1.03	1.05	1.05	1.05	1.07	1.05
TPH/DP	4.11	4.08	4.19	4.22	4.06	4.11	4.15	4.41	4.27
COAL PULVERIZER 1H									
PULV COAL FLOW	52.7	51.8	51.3	51.6	53.0	53.1	53.3	53.4	53.0
FEEDER SPEED	77.5	76.2	75.4	75.8	78.0	78.0	78.4	78.6	77.9
PULV PA FLOW	92.4	91.8	91.3	91.7	92.5	92.6	92.8	93.0	92.7
PA DAMPER POS	83.6	82.6	79.9	80.8	82.1	82.8	83.3	81.3	81.3
PULV INLET TEMP	341.6	330.1	301.0	334.2	343.2	347.5	324.1	378.4	377.9
PULV DISCH TEMP	149.6	150.5	149.3	149.9	149.1	150.8	149.7	149.8	150.2
PULV DIFF PRESS	17.2	17.0	16.6	16.9	17.1	16.8	17.0	15.9	15.7
PULV AMPS	59.0	58.9	60.2	59.2	58.9	58.7	59.3	57.4	56.9
AMPS/DP	3.43	3.47	3.62	3.51	3.44	3.48	3.48	3.62	3.62
TPH/AMPS	0.89	0.88	0.85	0.87	0.90	0.90	0.90	0.93	0.93
TPH/DP	3.07	3.05	3.08	3.06	3.10	3.15	3.13	3.37	3.37
PULV AMP SWING									
A PULV	7.26	6.94	9.63	8.30	7.74	6.87	6.41	6.86	6.70
B PULV	6.66	6.30	6.00	6.10	6.63	6.48	6.06	6.33	6.38
C PULV	8.49	9.13	14.67	10.97	10.74	10.85	10.52	9.22	10.60
D PULV	6.08	5.96	6.05	6.16	5.71	5.92	6.11	6.49	6.89
E PULV	6.14	6.09	6.44	6.79	6.74	6.38	6.64	6.56	6.46
F PULV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
G PULV	5.87	6.02	5.83	6.25	5.92	6.09	5.99	6.32	5.96
H PULV	5.72	5.28	5.75	6.00	5.79	6.12	6.13	5.39	5.15
CLEANLINESS FACTOR									
WATERWALLS	0.79	0.83	0.79	0.86	0.84	0.83	0.85	0.90	0.85
PSH SECTION	0.89	0.91	0.94	0.93	0.91	0.89	0.87	0.86	0.91
SSH PLATEN SECTION	0.83	0.85	0.71	0.91	0.84	0.80	0.84	0.89	0.74
SSH INTERMEDIATE SEC	0.70	0.75	0.67	0.72	0.64	0.64	0.74	0.71	0.64
SSH OUTLET SECTION	0.70	0.74	0.74	0.74	0.69	0.64	0.71	0.75	0.70
PRIMARY RH SECTION	0.75	0.63	0.83	0.68	0.80	0.84	0.76	0.65	0.77
RH OUTLET SECTION	0.89	0.97	1.02	0.92	0.90	0.87	0.85	0.87	0.87
ECONOMIZER SECTION	0.79	0.79	0.86	0.84	0.79	0.78	0.74	0.73	0.67

IP10_003427

BOILER- OVERFIRE A
NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 *14:45*	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 *16:30*
[illegible]		
UNIT LOAD	950.2	950.1
TURBINE THROTTLE PRES	2397.9	2401.0
THROTTLE TEMP	1000.3	1002.1
TURBINE STEAM FLOW	6767.8	6776.7
STEAM FLOW (FW + SSF)	6760.9	6769.2
FDW FLOW TO ECONOMI	6705.8	6707.7
TOTAL COAL FLOW	373.2	371.1
TOTAL FUEL FLOW	373.1	371.3
TOTAL AIR FLOW	85.1	84.6
EAST FLUE GAS O2	2.7	2.6
WEST FLUE GAS O2	2.7	2.6
EAST FLUE GAS COMB	0.0	0.0
OVERFIRE AIR		
OFA SW 1/3 DMPR P	0.9	0.9
OFA SE 1/3 DMPR P	2.0	2.0
OFA NW 1/3 DMPR P	0.0	0.0
OFA NE 1/3 DMPR P	5.9	5.9
OFA SW 2/3 DMPR P	46.0	45.9
OFA SE 2/3 DMPR P	45.8	45.8
OFA NW 2/3 DMPR P	42.6	42.6
OFA NE 2/3 DMPR P	60.0	59.9
OFA SW INLET DMPR P	99.2	99.2
OFA SE INLET DMPR P	99.0	99.0
OFA NW INLET DMPR P	97.9	97.9
OFA NE INLET DMPR P	98.7	98.7
OFA TO TOTAL AIR RATIO	11.3	11.3
SW OFA FLOW	214.8	215.9
SE OFA FLOW	214.0	211.0
NW OFA FLOW	217.4	215.8
NE OFA FLOW	211.0	209.3
TOTAL OFA AIR	858.5	853.6
[illegible]		
West Side O2	3.36	3.36
East Side O2	4.08	4.08
O2 Average	3.72	3.72
West Side CO2	14.55	
East Side CO2	14.86	

IP10_003428

BOILER- OVERFIRE A

NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
CO2 Average	14.70	
West Side NOx	270.63	
East Side NOx	203.13	
NOx Average	236.88	
Low Range CO Analyzer We	253.9	
Low Range CO Analyzer Ea	98.0	
Low Range CO Analyzer Ave	175.9	
High Range CO Analyzer W	249.4	
High Range CO Analyzer Ea	103.1	
High Range CO Analyzer Av	176.2	
Stack CO	184.3	184.3
Stack CO- corrected	161.1	161.1
CO converted #/mbtu	0.131	0.131
CO converted #/hr	1593	1581
[illegible]		
CO2	12.72	12.59
NOx PPM	226	222
NOx lb/mbtu	0.382	0.379
Stack Flow	136,354,968	135,369,798
CALCS		
Excess Air @ furn	3.9	3.5
Diff O2 CR- O2 grid	-1.01	-1.09
NOX Reduction (#/mbtu), s	8.1	
NOX Reduction (#/mbtu), v	38.5	
CO Increase (ppm), same C	92.2	
	92.2	
CO Increase (ppm), max ba	-6.8	
CO Increase (#/mbtu)	92.0	
[illegible]		
HHV	11618	
MAF HHV	14117	
% MOISTURE	8.38	
% ASH	9.32	
% SULFUR	0.52	
% CARBON	65.44	
% HYDROGEN	4.1	
% NITROGEN	1.46	

BOILER- OVERFIRE A
NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
% OXYGEN	10.78	
COAL..AS-FIRED		
HHVC	12591.2	12591.2
% TOTAL MOISTURE	4.3	4.3
% ASH	8.8	8.8
% SULFUR	0.9	0.9
% CARBON	70.5	70.5
% HYDROGEN	4.5	4.5
% NITROGEN	1.6	1.6
% OXYGEN	9.3	9.3
[illegible]		
LOI AVE (IPSC)		0.93
LOI EAST (IPSC)		1.01
LOI WEST (IPSC)		0.85
AEA EAST		15
AEA WEST		16
COLOR EAST		611
COLOR WEST		611
[illegible]		
UNIT		
GROSS CAPACITY	950.2	950.1
AUXILIARY POWER	55.5	55.3
GROSS UNIT HEAT RATE		
NET UNIT HEAT RATE I/O		
% AUX POWER		
STEAM TURBINE		
CORR GROSS CAPACITY		
NET TURBINE HEAT RATE		
CYCLE LOSSES		
THROTTLE FLOW		
FEEDWATER FLOW	6705.8	6707.7
CORR THROTTLE FLOW		
ECONOMIZER INLET TEM	547.5	547.5
AMBIENT CONDITIONS		
AMBIENT AIR TEMP	68.3	68.2
WET BULB TEMP	55.9	54.9
ATMOSPHERIC PRESSUR	12.4	12.4
BOILER		
BOILER EFF (HL Method)	89.7	89.7
BOILER EFF (Input-Output	82.9	83.3
BLOWDOWN FLOW		
SH SPRAY FLOW	56.4	62.8

BOILER- OVERFIRE A

NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
PMAX SH SPRAY FLOW	81.0	89.4
RH SPRAY FLOW	50.3	26.5
PMAX RH SPRAY FLOW	168.2	80.4
TOTAL AIR FLOW	85.1	84.6
EXCESS AIR	15.28	14.80
TOTAL FUEL FLOW	373.1	371.3
PMAX BACKCALC COAL F	337.2	338.4
REHEAT DAMPER POS	30.4	30.6
SUPERHEAT DAMPER PO	105.0	105.0
BOILER DUTY (HEAT INPU		
BOILER CONDITIONS		
EAST FLUE GAS O2	2.7	2.6
WEST FLUE GAS O2	2.7	2.6
SCRUB INLET SO2	365.7	376.0
STACK NOX	224.0	222.9
STACK NOX CONVERTED	0.382	0.378
O2 TRIM SETPOINT	46.4	46.4
CEM STACK VOL FLOW	136.3	135.7
PMAX CALC STACK VOL F	145.0	143.6
PMAX BLR GAS FLOW	8,449,389	8,370,219
PMAX BLR AIR FLOW RAT	7,776,545	7,700,283
BOILER HEAT DUTY		
BLR HEAT DUTY	7579.8	7575.9
WATER WALLS HEAT DUT	3233.9	3224.0
SSH PLATENS HEAT DUT	543.3	554.4
SSH INT SECTION HEAT D	606.1	622.9
SSH OUTLET SECTION HE	484.1	480.3
RH OUTLET SECTION HEA	857.2	847.5
PSH SECTION HEAT DUTY	1041.5	1032.8
ECON SECTION HEAT DU	288.7	287.0
PRI RH SECTION HEAT DU	503.0	429.1
TEMPS AIR/GAS		
AIR TEMP ENT SAH 1A	79.9	80.2
AIR TEMP ENT SAH 1B	79.6	80.3
AIR TEMP LVG SAH 1A	718.7	719.5
AIR TEMP LVG SAH 1B	718.1	718.8
FLAME GAS TEMP	3587.2	3616.6
SSH PLATENS GAS OUT T	2228.9	2244.7
SSH INT GAS IN TEMP	2228.9	2244.7
SSH INT GAS OUT TEMP	1996.7	2004.5
SSH OUTLET BANK GAS (	1809.0	1818.3
RH OUTLET BANK GAS O	1475.6	1483.8
PRI RH BANKS GAS IN TE	1858.3	1673.9
RH SECTION GAS OUT TE	753.5	758.0
TARGET RH EXIT GAS TE	760.1	760.0

IP10_003431

BOILER- OVERFIRE A
NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
PSH OUTLET GAS TEMP	954.1	954.8
PSH / ECON EXIT GAS TE	803.0	801.1
TARGET ECON EXIT GAS	760.0	760.0
AVE ECON EXIT GAS TEM	790.1	790.3
TARGET EXIT GAS TEMP	760.0	760.0
TEMPS STM/WTR		
ECON INLET WATER TEM	547.5	547.5
	548.8	548.8
TSAT AT DRUM PRESSUR	680.5	680.5
1ST STAGE SH ATTEMP I	745.4	744.6
	742.6	741.4
1ST STAGE SH ATTEMP C	739.4	739.0
	739.8	738.7
2ND STAGE SH ATTEMP I	807.5	808.2
	810.3	810.9
2ND STAGE SH ATTEMP C	801.7	800.4
	801.9	801.8
SSH INT BANK OUTLET TE	904.0	906.3
MAIN STEAM TEMP	1000.3	1002.1
COLD REHEAT INLET TEM	617.2	624.4
	617.4	624.7
PRI RH SECTION STM OU	725.6	730.5
RH TURBINE INLET TEMP	1009.7	1012.6
RH TURBINE INLET TEMP	998.5	1001.7
BLR HOT REHEAT AVE TE		
STEAM TEMP PICKUP		
DRUM THRU PSH	63.4	62.4
PLATENS	69.4	70.7
SSH INT BANK	102.1	105.1
SSH OUT BANK	96.4	95.8
PRI RH SECTION	108.2	105.9
RH OUTLET SECTION	278.7	276.8
FLOWS WTR/STM		
FEEDWATER FLOW (FOX	6946.4	6943.9
FEEDWATER FLOW (CCS	6705.8	6707.7
STEAM FLOW (FFW + SPR	6760.9	6769.2
STEAM FLOW OFF 1ST ST	6767.5	6776.4
PMAX THROTTLE FLOW	6791.2	6795.4
ECON OUTLET		
EAST ECON O2 PROBE 1A	2.9	2.8
EAST ECON O2 PROBE 2A	3.0	2.9
EAST ECON O2 PROBE 3A	2.4	2.3
EAST ECON O2 PROBE 4A	2.8	2.7
EAST FLUE GAS O2	2.7	2.6

IP10_003432

BOILER- OVERFIRE A

NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
WEST ECON O2 PROBE 1	2.5	2.4
WEST ECON O2 PROBE 2	4.3	4.1
WEST ECON O2 PROBE 3	1.8	1.7
WEST ECON O2 PROBE 4	2.3	2.1
WEST FLUE GAS O2	2.7	2.6
SELECTED ECON OUT O2	2.71	2.63
TARGET ECON OUT O2	3.09	3.09
EXCESS AIR %	15.3	14.8
CARBON DIOXIDE %	22.3	22.4
AIR/DRAFT PRESSURE		
SEC AIR DUCT PR E	4.2	4.2
SEC AIR DUCT PR W	4.5	4.5
FURNACE PRESSURE	-0.5	-0.5
SG EAST FLUE GAS PR	-0.2	-0.3
SG SEC SUPHTR GAS PR	-0.9	-0.8
SG HORIZ RH OUT PR	-2.7	-2.6
SG PENDANT OUT PR	-1.5	-1.5
SG PRI SUPHTR OUT PR	-2.8	-2.8
SG ECON OUTLET PR	-3.4	-3.3
SEC AH 1A INLET PR	-4.9	-4.8
SEC AH 1B INLET PR	-4.8	-4.8
ID FAN SUCTION PRESS	-23.5	-23.4
ID FAN 1A OUTLET PR	5.5	5.4
ID FAN 1B OUTLET PR	5.2	5.1
ID FAN 1C OUTLET PR	5.1	5.0
ID FAN 1D OUTLET PR	5.3	5.2
BAGHOUSE CASING DELT		
A CASING	6.6	6.6
B CASING	6.7	6.7
C CASING	7.2	7.1
FORCED DRAFT FAN 1A		
FD Fan Disc Press- A		
Sec Air Duct- East		
SEC AIR FLOW 1A	76.7	76.3
FD FAN 1A FLOW	851.3	844.7
FAN BLADE PITCH	62.4	61.8
FD FAN 1A D/P	11.0	11.1
MOTOR AMPS	214.8	213.9
CORR ACTUAL HEAD	9.9	9.9
AIR HORSEPOWER		
FORCED DRAFT FAN 1B		
FD Fan Disc Press- B		

IP10_003433

BOILER- OVERFIRE A

NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
Sec Air Duct- West		
SEC AIR FLOW 1B	78.4	77.8
FD FAN 1B FLOW	868.8	865.3
FAN BLADE PITCH	61.5	61.4
FD FAN 1B D/P	11.3	11.2
MOTOR AMPS	224.0	223.2
CORR ACTUAL HEAD	10.1	9.9
AIR HORSEPOWER		
PRI AIR DUCT PRESS	44.9	44.8
PRIMARY AIR FAN 2A		
PA FAN FLOW 2A	32.3	32.1
MOTOR AMPS	309.3	309.2
INLET VANE CONTROL %	32.6	32.7
PRIMARY AIR FAN 2B		
PA FAN FLOW 2B	33.4	33.4
MOTOR AMPS	318.3	318.0
INLET VANE CONTROL %	32.7	32.6
SECONDARY AIR HEATER		
AIR ENT SEC AH 1A	79.9	80.2
AIR LVG SEC AH 1A	718.7	719.5
GAS ENT SEC AH 1A	788.3	788.6
GAS LVG SEC AH 1A	322.1	323.5
FLUE GAS TEMP DROP	466.2	465.2
AIR HEATER TEMP HEAD	708.4	708.4
DROP/HEAD	65.81	65.66
SAH 1A EFFICIENCY - AIR	89.8	89.9
SAH 1A EFFICIENCY - GAS	58.3	58.1
SAH 1A AIR TO GAS LEAK	23.4	23.4
SAH 1A LEAKAGE (O2 ME	23.2	23.2
COLD END AVE TEMP	196.8	198.0
DIFFERENTIAL PRESS	9.1	9.0
MOTOR AMPS	31.0	30.9
SECONDARY AIR HEATER		
AIR ENT SEC AH 1B	79.6	80.3
AIR LVG SEC AH 1B	718.1	718.8
GAS ENT SEC AH 1B	792.7	792.0
GAS LVG SEC AH 1B	311.4	313.2
FLUE GAS TEMP DROP	481.2	478.8
AIR HEATER TEMP HEAD	713.0	711.7
DROP/HEAD	67.49	67.28
SAH 1B EFFICIENCY - AIR	89.9	90.1
SAH 1B EFFICIENCY - GAS	63.5	63.2
SAH 1B AIR TO GAS LEAK	13.3	13.2

BOILER- OVERFIRE A
NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
SAH 1B LEAKAGE (O2 ME	13.2	13.2
COLD END AVE TEMP	206.0	207.7
DIFFERENTIAL PRESS	9.1	9.1
MOTOR AMPS	31.2	31.4
PRIMARY AIR HEATER 2A		
AIR ENT PRI AH 2A	120.0	120.6
AIR LVG PRI AH 2A	525.3	526.6
GAS ENT PRI AH 2A	788.3	788.6
GAS LVG PRI AH 2A	299.6	300.5
FLUE GAS TEMP DROP	488.7	488.1
AIR HEATER TEMP HEAD	668.3	668.0
DROP/HEAD	73.13	73.07
PAH 2A EFFICIENCY - AIR	60.6	60.8
PAH 2A EFFICIENCY - GA	73.1	73.1
COLD END AVE TEMP	207.2	207.7
DIFFERENTIAL PRESS	2.4	2.3
MOTOR AMPS	3.4	3.4
PRIMARY AIR HEATER 2B		
AIR ENT PRI AH 2B	118.0	118.1
AIR LVG PRI AH 2B	516.7	517.1
GAS ENT PRI AH 2B	794.1	792.7
GAS LVG PRI AH 2B	300.4	301.1
FLUE GAS TEMP DROP	493.7	491.7
AIR HEATER TEMP HEAD	676.0	674.6
DROP/HEAD	73.03	72.88
PAH 2B EFFICIENCY - AIR	59.1	59.2
PAH 2B EFFICIENCY - GA	72.9	72.9
COLD END AVE TEMP	211.3	211.9
DIFFERENTIAL PRESS	2.0	2.0
MOTOR AMPS	3.6	3.6
TOTAL AH LKG (CO2 MET	9.9	10.2
TOTAL AH LKG (GAS WT I	18.1	18.1
TOTAL AH LKG (O2 METH	18.0	18.0
INDUCED DRAFT FAN 1A		
XFMR 1A1 AMPS	335.1	335.7
XFMR 1A2 AMPS	332.3	332.9
ID FAN 1A SPEED	834.2	832.7
INDUCED DRAFT FAN 1B		
XFMR 1B1 AMPS	353.7	351.7
XFMR 1B2 AMPS	356.4	354.4
ID FAN 1B SPEED	837.3	835.8
INDUCED DRAFT FAN 1C		

BOILER- OVERFIRE A
NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
XFMR 1C1 AMPS	365.0	363.9
XFMR 1C2 AMPS	360.2	358.5
ID FAN 1C SPEED	852.4	850.9
INDUCED DRAFT FAN 1D		
XFMR 1D1 AMPS	359.4	357.2
XFMR 1D2 AMPS	361.3	359.1
ID FAN 1D SPEED	843.9	842.3
TOTAL ID FAN AMPS	2823.4	2813.4
COAL PULVERIZER 1A		
PULV COAL FLOW	49.7	49.5
FEEDER SPEED	73.2	72.8
PULV PA FLOW	91.8	91.8
PA DAMPER POS	72.6	73.0
PULV INLET TEMP	285.1	283.8
PULV DISCH TEMP	150.0	149.9
PULV DIFF PRESS	12.4	12.4
PULV AMPS	72.0	71.4
AMPS/DP	5.83	5.78
TPH/AMPS	0.69	0.69
TPH/DP	4.03	4.00
COAL PULVERIZER 1B		
PULV COAL FLOW	55.7	55.5
FEEDER SPEED	81.9	81.6
PULV PA FLOW	91.7	91.5
PA DAMPER POS	84.9	84.7
PULV INLET TEMP	318.6	316.0
PULV DISCH TEMP	151.4	151.3
PULV DIFF PRESS	16.5	16.5
PULV AMPS	57.6	57.6
AMPS/DP	3.49	3.50
TPH/AMPS	0.97	0.96
TPH/DP	3.38	3.37
COAL PULVERIZER 1C		
PULV COAL FLOW	54.5	54.2
FEEDER SPEED	80.0	79.7
PULV PA FLOW	90.7	90.5
PA DAMPER POS	77.5	76.6
PULV INLET TEMP	309.1	308.1
PULV DISCH TEMP	151.0	150.9
PULV DIFF PRESS	15.5	15.0
PULV AMPS	68.4	69.4
AMPS/DP	4.42	4.63
TPH/AMPS	0.80	0.78

BOILER- OVERFIRE A

NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
TPH/DP	3.52	3.61
COAL PULVERIZER 1D		
PULV COAL FLOW	55.0	54.7
FEEDER SPEED	80.9	80.5
PULV PA FLOW	91.3	91.1
PA DAMPER POS	74.4	74.1
PULV INLET TEMP	318.5	315.2
PULV DISCH TEMP	152.6	152.4
PULV DIFF PRESS	16.7	16.7
PULV AMPS	60.3	60.2
AMPS/DP	3.61	3.60
TPH/AMPS	0.91	0.91
TPH/DP	3.29	3.27
COAL PULVERIZER 1E		
PULV COAL FLOW	52.0	51.7
FEEDER SPEED	76.4	76.0
PULV PA FLOW	89.5	89.3
PA DAMPER POS	84.8	84.6
PULV INLET TEMP	307.5	302.9
PULV DISCH TEMP	151.2	151.2
PULV DIFF PRESS	18.9	18.9
PULV AMPS	64.1	64.2
AMPS/DP	3.39	3.39
TPH/AMPS	0.81	0.81
TPH/DP	2.75	2.73
COAL PULVERIZER 1F		
PULV COAL FLOW	No good data for this	No good data for this
FEEDER SPEED	No good data for this	No good data for this
PULV PA FLOW	0.0	0.0
PA DAMPER POS	1.3	1.3
PULV INLET TEMP	96.4	97.3
PULV DISCH TEMP	88.7	89.1
PULV DIFF PRESS	0.0	0.0
PULV AMPS	0.0	0.0
AMPS/DP	#DIV/0!	0.00
TPH/AMPS	#VALUE!	#VALUE!
TPH/DP	#VALUE!	#VALUE!
COAL PULVERIZER 1G		
PULV COAL FLOW	54.0	53.7
FEEDER SPEED	79.4	78.9
PULV PA FLOW	92.1	91.5
PA DAMPER POS	76.4	76.3
PULV INLET TEMP	323.9	315.4
PULV DISCH TEMP	151.1	151.1

BOILER- OVERFIRE A

NOTE: Master data do

PARAMETER	Test # 18a (Day4-T3) 9/9/03 Tue 14:15 14:45	Test # 18b (Day4-T3) 9/9/03 Tue 14:30 16:30
PULV DIFF PRESS	12.8	13.0
PULV AMPS	52.5	52.2
AMPS/DP	4.11	4.01
TPH/AMPS	1.03	1.03
TPH/DP	4.23	4.12
COAL PULVERIZER 1H		
PULV COAL FLOW	52.4	52.1
FEEDER SPEED	77.0	76.6
PULV PA FLOW	92.2	92.0
PA DAMPER POS	82.4	82.7
PULV INLET TEMP	326.2	328.8
PULV DISCH TEMP	149.6	149.2
PULV DIFF PRESS	15.8	15.8
PULV AMPS	57.7	57.5
AMPS/DP	3.64	3.64
TPH/AMPS	0.91	0.91
TPH/DP	3.31	3.30
PULV AMP SWING		
A PULV	11.56	10.84
B PULV	6.21	6.01
C PULV	15.75	16.37
D PULV	6.37	6.14
E PULV	6.50	6.17
F PULV	0.00	0.00
G PULV	6.21	6.69
H PULV	5.10	5.58
CLEANLINESS FACTOR		
WATERWALLS	0.84	0.84
PSH SECTION	0.92	0.89
SSH PLATEN SECTION	0.73	0.74
SSH INTERMEDIATE SEC	0.62	0.63
SSH OUTLET SECTION	0.64	0.63
PRIMARY RH SECTION	0.69	0.74
RH OUTLET SECTION	0.83	0.82
ECONOMIZER SECTION	0.70	0.73

Derivation of test data curve fits - CO vs O_2

The CO operating curves for each OFA damper setting were calculated with a least squares fit through the data points using the following equation:

$$y = cx^b$$

where y is corrected stack CO (ppm), x is flue gas O_2%, c and b are constants.

The shape of the curves using this equation resemble published CO/excess air combustion curves. Plots of the CO data from all the OFA damper settings also show a power curve correlation to flue gas O_2.

The following tables show the test CO data points, derived constants, and r^2 values for each OFA damper setting test series.

No Overfire Air	
%O2	CO (ppm)
1.7	696
2.1	240
2.6	41
3.1	2.3
3.2	13
r^2 = 0.8916 c = 47259 b = -7.6817	

10% Overfire Air	
%O2	CO (ppm)
1.7	899
1.9	242
2.5	54
3.0	22
3.3	3
r^2 = 0.9568 c = 66265 b = -7.9824	

12% Overfire Air	
%O2	CO (ppm)
1.9	212
2.5	169
2.7	161
3.0	20
r^2 = 0.477 c = 4029.2 b = -4.0112	

14% Overfire Air	
%O2	CO (ppm)
2.0	302
2.4	50
2.7	43
3.8	33
r^2 = 0.7097 c = 1372.4 b = -3.0919	

Derivation of test data curve fits - NO_X vs O_2

A linear correlation was used to derive the NO_X relationship to flue gas O_2 for each overfire damper setting. A least squares curve fit was used to fit a straight line through the NO_X data using the equation:

$$y = mx + b$$

where y is the stack NO_X (#/mbtu), x is flue gas O_2%, and, m and b are constants.

The following tables show the test NO_X data points, derived constants, and r^2 values for each OFA damper setting test series.

No Overfire Air	
%O2	NOx (#/mbtu)
1.7	0.350
2.1	0.377
2.6	0.418
3.1	0.529
3.2	0.413
r^2 = 0.6079	
m = 0.0801	
b = 0.2136	

10% Overfire Air	
%O2	NOx (#/mbtu)
1.7	0.306
1.9	0.327
2.5	0.378
3.0	0.438
3.3	0.399
r^2 = 0.7961	
m = 0.0709	
b = 0.193	

12% Overfire Air	
%O2	NOx (#/mbtu)
1.9	0.342
2.5	0.382
2.7	0.417
3.0	0.382
r^2 = 0.9344	
m = 0.0658	
b = 0.2146	

14% Overfire Air	
%O2	NOx (#/mbtu)
2.0	0.314
2.4	0.359
2.7	0.377
3.8	0.375
r^2 = 0.5849	
m = 0.029	
b = 0.2772	